Arnold Schwarzenegger
Governor

IMPACT OF VARIATIONS IN RENEWABLE GENERATION ON CALIFORNIA'S NATURAL GAS INFRASTRUCTURE

PIER INTERIM PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

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October 2009
CEC-500-2009-083

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Commission Work Authorization No: MRA-056

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

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- Transportation

Impact of Variations in Renewable Generation on California's Natural Gas Infrastructure is an interim report as part of the Developing a Multi-State Natural Gas Infrastructure Simulation Model to Analyze the Value of Natural Gas Storage in California project (Contract Number 500-02-004, Work Authorization number MRA-056) conducted by ICF International. The information from this project contributes to PIER's Energy Systems Integration-Strategic Natural Gas Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916 654 4878.

Brock, Frank Edward (ICF International). 2009. *Impact of Variations in Renewable Generation on California's Natural Gas Infrastructure*. California Energy Commission, PIER's Energy Systems Integration-Strategic Natural Gas Program. CEC-500-2009-083.

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Abstract

This study analyzes the potential impacts of variations in renewable generation on California's natural gas infrastructure, assuming the achievement of a 33 percent Renewables Portfolio Standard by 2020. To control carbon emissions, many states, including California, have set standards to develop clean sources of energy. California's current target of 33 percent Renewables Portfolio Standard by 2020 is based on Executive Order S-14-08 signed by Governor Arnold Schwarzenegger on November 17, 2008. Some renewable technologies, such as wind, photovoltaic, and solar thermal have variability in their output due to weather conditions. Reductions in renewable generation can create a corresponding increase in gas demand for electricity generation and potentially could stress California's natural gas pipeline and storage infrastructure. This study focuses on the potential impact of variation in renewable generation on California's gas pipelines and storage capacity in 2020, the year when the proposed 33 percent Renewables Portfolio Standard is to be met.

Keywords: Renewable generation, natural gas, Renewables Portfolio Standard, Executive Order S-14-08, pipeline, storage, photovoltaic, solar thermal

Executive Summary

Introduction

In 2002, California established a Renewables Portfolio Standard (RPS) Program with the goal of increasing the percentage of renewable energy in the state's electricity mix to 20 percent by 2017. On November 17, 2008, Governor Arnold Schwarzenegger signed Executive Order S-14-08, which expanded the Renewables Portfolio Standard Program goal to 33 percent by 2020. Since natural gas-fueled backup generation is typically used for renewable sources, the researcher was contracted by the California Energy Commission (Energy Commission) to analyze the impacts a 33 percent Renewables Portfolio Standard Program in 2020 would have on California's natural gas infrastructure. The researcher previously developed a model for the Energy Commission that simulates the natural gas system within the state, which was used in conducting this study.

Purpose

The study was designed to understand how the variability of major forms of renewable generation could cause potential constraints on the natural gas pipeline and storage infrastructure within California and where these constraints would develop first within the system.

Project Objectives

This project was designed to analyze the ability of California's natural gas infrastructure to deal with the variability of renewable generation in a 33 percent RPS scenario in 2020. The specific objectives included:

- Understanding the impact of a 33 percent Renewables Portfolio Standard Program by 2020 on California's demand for natural gas.
- Understanding how natural gas demand in the state would further be impacted by variations in weather and certain forms of renewable generation.
- Identifying where potential constraints may develop within the system given these scenarios.

Project Outcomes

In this project, the researcher ran five cases representing mixtures of differing inputs – varying weather patterns, variations in renewable generation, and differing mixtures of renewable infrastructure. The exact breakdown of these case differences is described in the Overview of the Modeling Results section. Figure 1 shows the peak day gas consumption in California in each of these cases. Case 1 represents the base case with normal weather and no reduction in renewable generation within California. Case 4, the case with the highest peak day demand for natural gas, represents the scenario where California's renewable infrastructure used to meet its 2020 RPS is primarily wind, the generation from these renewable sources is at a reduced level, and adverse weather conditions are assumed.

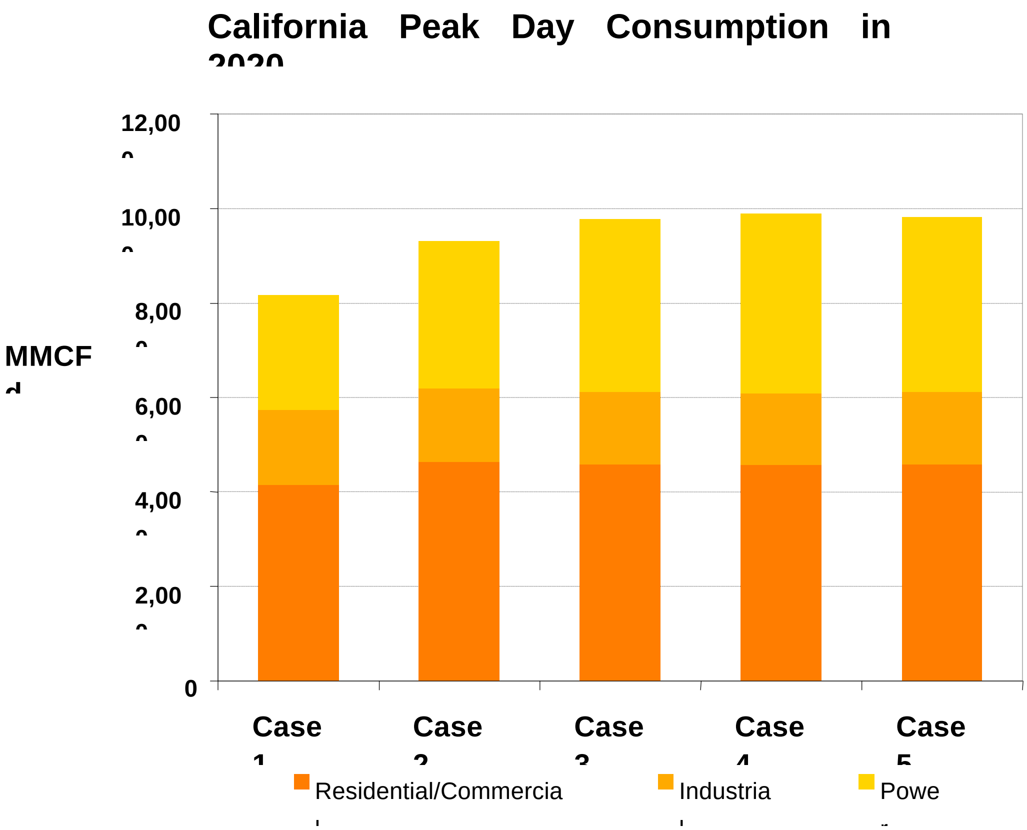

Figure 1: California January 2020 Peak Day Gas Consumption
Source: ICF International

The majority of the increased demand in each of the Cases 2 through Case 5 is filled by increased pipeline imports into Southern California with some additional imports in the north. Both Southern and Northern California have spare pipeline capacity on a peak day. In these scenarios, storage withdrawals on the peak day in January are at or near capacity at many fields within the state.

Conclusions and Recommendations

A 33 Percent Renewables Portfolio Standard Program Results in an Incremental Reduction in California's Gas Demand

With expected levels of renewable generation, normal weather and hydroelectric conditions, California's power sector gas consumption is projected to decline by 0.8 billion cubic feet per day (BCFd) by 2020. California's total gas demand is projected to decline by 0.9 BCFd by 2020 since other gas sectors are projected to be flat to down. Even with adverse weather and hydroelectric conditions, which increases average annual gas demand by 0.7 BCFd, gas consumption in 2020 is still projected to be lower than in 2008.

California’s Natural Gas Infrastructure Is Adequate to Handle Increases in Peak Day Gas Demand Caused by Reduced Renewable Generation

All of the cases with reduced renewable generation cause an incremental increase in January 2020 peak day gas demand of about 0.5 BCFd. These increases were not enough to cause significant problems for the state’s gas pipeline or gas storage infrastructure. Gas infrastructure within the state is generally adequate to meet the increased January peak day gas demands in all the reduced generation cases with the possible exception of the San Diego area distribution system, which appeared to be congested in both winter and summer peak gas demand periods. Additional pipeline and/or storage infrastructure may be required in this area to ensure system reliability.

Natural Gas Supply Options and Infrastructure Improvements Over Time

United States gas supplies are expected to increase by over 7 BCFd by 2020, mainly due to increases in domestic production. Growth in the Rockies’ gas production directly benefits California. Several planned pipeline projects will increase the supply of natural gas available to California. New storage capacity in California provides additional flexibility for meeting peak demand.

Technology Mix and Geographic Diversity in Renewable Generation Sources Minimizes the Potential Impact of Reduced Renewable Generation

While wind and solar generation varies due to changes in weather conditions, other renewable technologies, such as biomass, biogas, and geothermal, do not. Generation from these non-intermittent technologies will dampen the potential for variability in total renewable generation. Wind and solar technologies have distinct seasonal patterns, and, to some extent, these normal seasonal patterns complement each other. In the summer months, when electric load is highest, wind generation is at its lowest, but solar generation is at its highest. Geographic diversity also enhances the reliability of intermittent renewable technologies. For example, wind generation can be highly variable at any particular site in California. However, based on historical weather data, it appears unlikely that there would be unfavorable wind conditions simultaneously throughout the state.

Benefits to California

The results of this project will help California better understand the potential impacts of a 33 percent Renewables Portfolio Standard Program by 2020 on the natural gas infrastructure of the state. While renewable generation is not directly tied to natural gas, natural gas fuel for backup generation is a natural source for renewable generation, given the inherent variability of many renewable generation sources. This report not only shows the demand levels for natural gas in adverse situations, but also where potential bottlenecks and/or the constraints that may develop within California’s natural gas infrastructure in those scenarios. This information could be used to plan future infrastructure investments to help prevent these constraints from occurring.

1.0 Introduction

Earlier modeling work in this study assessed the use and value of natural gas storage in California. In the original work plan for the project, the next set of scenarios was to focus on the impact of liquefied natural gas (LNG) imports, disruptions to gas infrastructure, and/or increased gas-fired power generation. However, the California Energy Commission (Energy Commission) expressed a desire to redirect the effort to focus on the impact of California's increasing use of renewable energy on gas infrastructure, since gas-fired generation serves as a backup to renewable generation.

In the revised work plan, the focus for the remaining scenarios has been shifted to the potential impacts of variations in renewable generation on California's natural gas infrastructure, assuming the adoption of a 33 percent Renewables Portfolio Standard (RPS).

1.1. California's Renewables Portfolio Standard

Due to increasing interest in controlling carbon emissions, many states have begun to focus their attention not only on reducing the emissions from fossil fuel plants, but also on developing clean sources of energy. To this end, in the United States, 29 states have established renewable portfolio standards, which set goals for meeting a certain percentage of the states' electricity demand with renewable generation.

In 2002, California established its own Renewables Portfolio Standard Program, with the goal of increasing the percentage of renewable energy generation in the state's electricity mix to 20 percent by 2017. The *2003 Integrated Energy Policy Report* recommended accelerating that goal to 20 percent by 2010, and the *2004 Energy Report Update* further recommended increasing the target to 33 percent by 2020. The state's *Energy Action Plan II* also supported this goal.

In 2006, California State Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006) codified the 20 percent by 2010 goal. Under the 2006 law, electric utilities and others entities with retail electricity sales are required to increase their procurement of electricity from eligible renewable energy resources by at least 1 percent of their retail sales annually, until they reach 20 percent by 2010. On November 17, 2008, Governor Arnold Schwarzenegger signed Executive Order S-14-08, which expanded the RPS goal to 33 percent by 2020.

2.0 Overview of Task

By definition, several technologies can contribute to meeting the 33 percent RPS, including wind, photovoltaic (PV), solar thermal, biogas, biomass, geothermal, and small hydroelectric. Some renewable technologies, such as wind, PV, and solar thermal, have variability in their output due to weather conditions. The variability of generation from wind and solar technologies is different, so different mixes of technologies result in different degrees of variability in total RPS generation. Reductions in renewable generation can create a corresponding increase in gas demand for electricity generation, and potentially could stress California's natural gas pipeline and storage infrastructure. This study focuses on the potential impact of variation in renewable generation on California's gas pipelines and storage capacity in 2020, the year when the proposed 33 percent RPS is to be met.

3.0 Overview of Modeling Approach

As with the earlier modeling work that examined the impact of weather and hydroelectric generation on gas storage, this analysis is based on a multi-step process that makes use of three different models to analyze changes in natural gas demand, supply, and the utilization of gas infrastructure under different scenarios.

- Gas Market Model (GMM) – GMM creates a monthly projection for the entire North American natural gas market through 2020, including regional supply, demand, storage activity, inter-regional pipeline flows, and gas prices.
- Regional Infrastructure Assessment Modeling System (RIAMS) – RIAMS provides a much more detailed analysis of pipeline flows and storage activity within California for the forecast period 2019-2020 (when the 33 percent RPS target is met).
- Daily Gas Load Model (DGLM) – DGLM is used to create a daily load profile for January 2020, California's peak gas demand month. The daily load profile is input into RIAMS to project peak day pipeline flows and storage activity. The results are vital to assessing the adequacy of gas infrastructure to satisfy peak day loads.

The renewable generation cases we modeled were based on several 33 percent RPS scenarios developed for the California Public Utility Commission (CPUC) by Energy and Environmental Economics, Incorporated, for the 33% Implementation Analysis Working Group Meeting on January 15, 2009.[1] After discussions with Energy Commission staff, the authors chose the following three scenarios from the workgroup presentation: the 33 percent Reference Case, the High Wind Case, and the High Central Station Solar case. While the total annual RPS generation is the same in each of these three scenarios, they have different mixes of renewable technologies to meet the standard. When implemented in the natural gas models, the different technology mix represented in each scenario results in both different monthly generation patterns and different projections for reduced levels of generation from renewables that could result from variability in weather.

A total of five renewable generation cases were modeled:

- **Case 1: Thirty-Three Percent RPS Reference Scenario, Expected Renewable Generation, Normal Weather**

  This case assumes California's RPS is 33 percent of electricity sales by 2020, renewable capacity is sufficient to meet this standard, and renewable generation in 2020 is at the expected level. The mix of technologies used to meet the RPS is consistent with the CPUC's 33% Reference scenario. This case also assumes normal weather conditions.

- **Case 2: Thirty-Three Percent RPS Reference Scenario: Expected Renewable Generation, Adverse Weather**

[1] California Public Utility Commission's 33% Implementation Analysis Working Group presentation, provided via email by Michael Magaletti, Energy Commission, February 9, 2009.

This case assumes the same level of renewable generation as in Case 1, but instead of normal weather it assumes adverse temperatures conditions (that is, hot summer and cold winter) and reduced generation from large hydroelectric facilities. This case is needed to differentiate the impact of temperature and hydroelectric conditions on gas demand from the impact of changes in renewable generation in Cases 3, 4, and 5.

- **Case 3: Thirty-Three Percent RPS Reference Scenario: Reduced Renewable Generation, Adverse Weather**

  This case assumes the same RPS and technology mix as Case 1, but wind and solar generation are assumed to be below expected levels in 2020, and this deficit is replaced solely with gas-fired generation. This case also assumes the same adverse temperature and hydroelectric conditions as in Case 2.

- **Case 4: Thirty-Three Percent RPS High Wind Scenario: Reduced Renewable Generation, Adverse Weather.**

  In this case, the mix of technologies used to meet the 33 percent RPS is consistent with the CPUC's High Wind scenario. Wind and solar generation are assumed to be below expected levels in 2020, and this deficit is replaced solely with gas-fired generation. This case also assumes the same adverse temperature and hydroelectric conditions as in Case 2.

- **Case 5: Thirty-Three Percent RPS Solar Scenario: Reduced Renewable Generation, Adverse Weather.**

  In this case, the mix of technologies used to meet the 33 percent RPS is consistent with the CPUC's High Central Station Solar scenario. Wind and solar generation are assumed to be below expected levels in 2020, and this deficit is replaced solely with gas-fired generation. This case also assumes the same adverse temperature and hydroelectric conditions as in Case 2.

The procedure used to model the cases is outlined in Figure 2. For each of the five cases, the authors first ran the GMM with the assumed level of renewable generation in California to determine changes in regional gas consumption, production, storage injections and withdrawals, gas prices, and inter-regional pipeline flows. Data from the GMM was then passed to the monthly version of the RIAMS model, which was used to project changes in the utilization of pipeline and storage capacity in California and surrounding states as gas demand at specific power plants changed in response to the change in renewable generation. The monthly version of RIAMS was run for the 12 months from November 2019 to October 2020. Data from the monthly version of RIAMS, along with the daily gas load projection from the DGLM, was passed to the daily version of RIAMS, which was used to project the utilization of California's gas pipelines and storage facilities for each day of January 2020. Of particular interest is the RIAMS solution for the peak day of January, which is typically the highest demand day of the year in California. If California's natural gas infrastructure is not capable of meeting changes in the gas load caused by variations in renewable generation, deficiencies in the infrastructure would show up on the peak gas demand day.

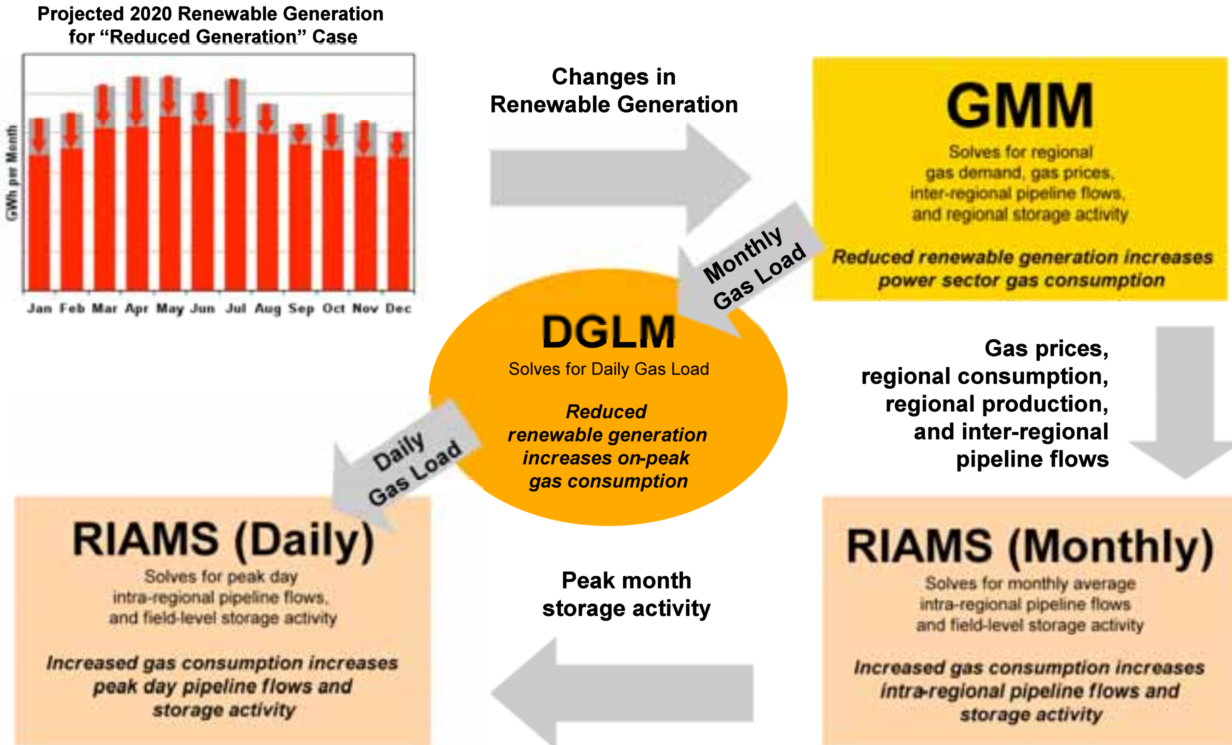

Figure 2: Modeling of Renewable Generation Cases

Source: ICF International

3.1. Common Assumptions in All Cases

The earlier temperature/hydroelectric modeling work performed under this contract was based on the January 2008 Base Case. Updates were done on the gas market Base Case projection each month to reflect recent developments in the gas market, so the authors adopted the January 2009 Base Case at the starting point for the renewable analysis. The January 2009 Base Case projection includes historical macroeconomic inputs for 2008 (which are lower than our January 2008 projection) and the latest projection, which assume a recession lasting through the end of 2009. The recession reduces demand for natural gas over the next year, but the United State Gross Domestic Product growth returns to the long-run expected average of 3.0 percent per year by 2010. The January 2009 Base Case also includes the researcher's most recent reconnaissance on natural gas pipeline and storage additions throughout North America.

3.1.1. Assumptions for the U.S. Natural Gas Market

Annual gas consumption in the United States is expected to increase by 2.2 trillion cubic feet (TCF) by 2020, as shown in Table 1. Most of the increase in the United States gas consumption is due to increased gas demand for electricity generation. Over the same period, net exports to Mexico are expected to increase by 0.4 TCF per year, yielding an increase in total annual demand of 2.6 TCF.

Most of the increase in the United States gas supply comes from domestic production, which is projected to increase by 2.3 TCF. Gas production increases are concentrated in the Rockies, Mid-continent shales, and Marcellus Shale. Net LNG imports are also up by 1.2 TCF, which more than offsets the 0.9 TCF decline in net imports from Canada.

Obviously, California benefits directly from growing gas production in the Rockies, as more gas will be available on the Kern River Pipeline, and the new Ruby Pipeline will allow additional supplies from the Rockies to flow west. California also benefits indirectly from increasing production east of the Rockies in areas such as the Mid-continent shales. Increasing production east of the Rockies means more natural gas from Texas could be available to markets in the West.

Table 1: U.S. Natural Gas Supply and Demand through 2020

U.S. Natural Gas Balance, Bcf per Year	2007	2008	2009	2010	2015	2020	2008-20 Delta	2008-20 CAGR
Total Consumption	23,189	22,996	22,703	22,405	24,675	25,175	2,179	0.8%
+ Net Storage Injections (+) or Withdrawals (-)	(177)	(43)	172	(88)	(153)	87	130	n/a
+ Net Exports to Mexico	277	357	409	298	536	759	402	6.5%
Total Demand	23,289	23,310	23,284	22,615	25,058	26,021	2,711	0.9%
Total Production	19,875	20,503	20,621	19,489	22,331	22,815	2,312	0.9%
+ Net LNG Imports	702	287	324	1,002	1,050	1,524	1,237	14.9%
+ Net Imports from Canada	3,062	2,827	2,588	2,324	1,912	1,890	(937)	-3.3%
Total Supply	23,639	23,617	23,533	22,816	25,293	26,230	2,613	0.9%
Balancing Item*	350	307	249	201	235	209	(97)	-3.1%

* Total Supply less Total Demand; also referred to as unaccounted for gas.

Source: ICF International

3.1.2. Assumptions for California's Electric Power Sector

For the cases used in the renewable analysis, the authors modified some of the model input assumptions to be consistent with other California Energy Commission assumptions about California's electricity market. In renewable cases, California's electricity demand growth rate is consistent with the Energy Commission's 2007 projection of 1.1% per year growth through 2020.[2] The authors used the Energy Commission's 2007 load growth projection because the updated projection was still being developed when they were conducting this study. Because of the 2008/09 recession, electricity demand in the California Institute for Energy and the Environment (CIEE) Base Case does not match the Energy Commission's 2007 projection for every year, but it does match the average long-run growth rate and the total level of electricity demand reached by 2020.

[2] *California Energy Demand 2008 - 2018: Staff Revised Forecast*, CEC-200-2007-015-SF2. Forecast extended to 2020 by Energy Commission staff.

The researcher modified the Base Case assumptions for renewable generation growth so it would be consistent with the 33 percent RPS standard. Using the Energy Commission's 2007 load projection, the researcher estimated that the net energy for load would be 353 terawatt-hours (TWh) in 2020, and retail electricity sales would be 309 TWh. To meet a 33 percent RPS, California would have to generate or import a total of 103 TWh of electricity from qualified renewable generators in 2020. Both Cases 1 and 2 assumes there will be 103 TWh of renewable generation in 2020, while the other three cases assumed reduced levels of renewable generation.

All three of the CPUC's 33 percent RPS scenarios will reach 103 TWh of RPS by 2020, but each has a unique mix of technologies, as shown in **Table 2**.[3] The Reference scenario assumes that wind generation provides about 37 percent of RPS generation, with 25 percent coming from solar technologies, and the remaining 38 percent coming from other technologies (biogas, biomass, geothermal, and small hydroelectric). The High Wind scenario assumes that wind makes up 47 percent of RPS generation, solar technologies 12 percent, and other technologies 41 percent. The Solar scenario assumes that solar technologies make up 26 percent of RPS generation, wind 36 percent, and other technologies 38 percent.

[3] The incremental increases for each of the scenarios shown in Table 2 are slightly different from those shown in the CPUC presentation, which totaled 74,650 GWh for each case. For this study, the increases in each type of generation were scaled down slightly so the expected level of RPS generation in 2020 in each scenario would total exactly one-third of electricity sales.

Table 2: Expected Renewable Generation by 2020 for Each 33% RPS Scenario

Generation in GWh per Year	2008 Base Generation*	Reference		High Wind		Solar	
		Incremental Increase	Total Generation	Incremental Increase	Total Generation	Incremental Increase	Total Generation
Wind	5,724	32,685	38,409	42,849	48,573	31,057	36,781
Solar (PV and Thermal)	724	24,815	25,539	11,448	12,172	26,383	27,107
Biomass	5,696	3,050	8,746	4,756	10,452	3,110	8,806
Biogas	-	2,078	2,078	2,078	2,078	2,078	2,078
Geothermal	12,951	11,520	24,471	13,034	25,985	11,520	24,471
Small Hydro	3,761	116	3,877	100	3,861	116	3,877
Total RPS Generation	28,856	74,264	103,120	74,264	103,120	74,264	103,120

* 2008 Base Generation - http://energyalmanac.ca.gov/electricity/total_system_power.html

Source: ICF International

California, as of 2009, has over 370 gas-fueled electric generating facilities with a total capacity of 40 GW.[4] About 52 percent of the existing gas-fueled capacity is located in Southern California, 33 percent in Northern California, and 15 percent in Central California, as shown in Figure 3. In all of the renewable cases, gas-fueled capacity is expected to increase by 3 GW to a total capacity of 43 GW by 2020, with about two-thirds of the new capacity being combustion turbines to serve peak-demand needs. The additions of new capacity are assumed to be distributed within the state roughly in proportion to the current location of existing gas-fueled capacity.

The researcher assumes, in all cases, that new regulations on water discharge from plants using once-through cooling will not have any significant impact on power sector gas demand in California. It is unlikely that new regulations would force the retirement of nuclear plants, and any gas-fired plants that may be retired would likely be replaced with new gas-fired capacity, which would cause very little net change in gas consumption.

[4] Nearly all these units use natural gas exclusively, but a small number (less than 2 percent) are dual-fueled (oil and gas) units. New capacity additions are expected to operate on gas only.

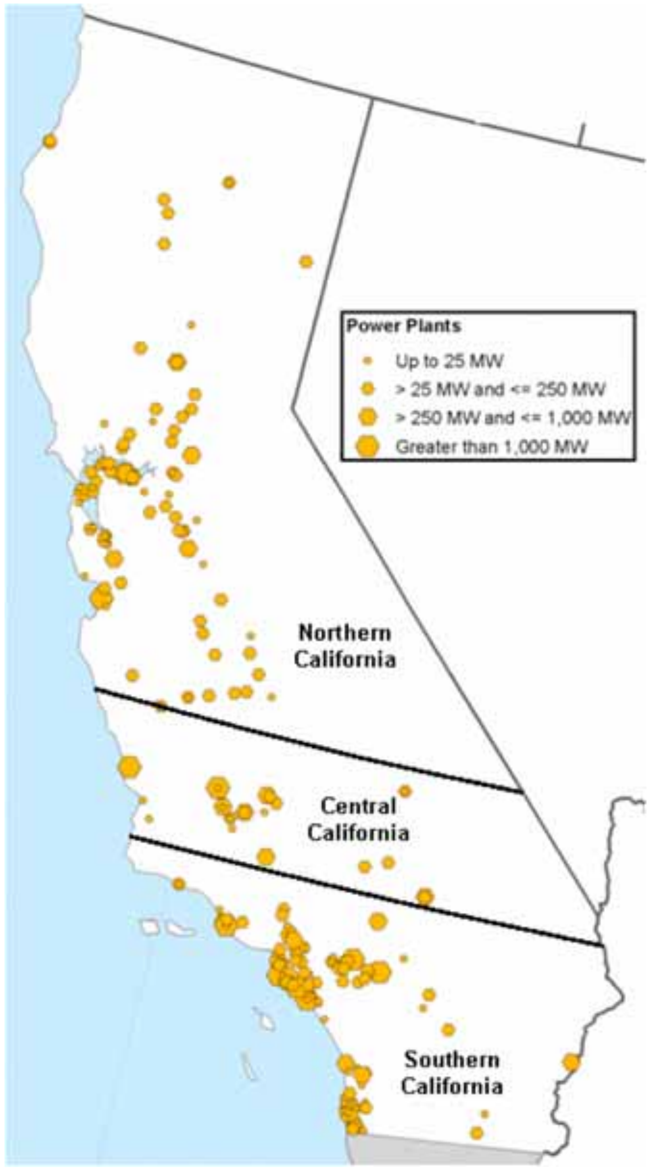

Figure 4: Existing Gas-Fueled Electric Power Plants in California

Source: ICF International, based on California Energy Commission database of existing power plants.

3.1.3. Assumptions for California's Natural Gas Infrastructure

All cases used in the renewable analysis used the same assumptions for North American gas pipeline and storage capacity. The researcher's assumptions for current and projected changes to natural gas infrastructure are based on publicly available information, such as pipeline bulletin boards, Federal Energy Regulatory Commission (FERC) filings, trade publications, and press releases. The Energy Commission has reviewed the assumptions that have a direct impact on California's gas infrastructure and did not provide any information to the contrary.

Maps outlining the assumptions for Central / Southern and Northern California's natural gas infrastructure are shown in Figure 5 and Figure 6, respectively. Southern / Central California has 7.6 BCFd of in-bound pipeline capacity on interstate pipelines and about 130 BCF of storage capacity with a maximum withdrawal capability of 3,200 million cubic feet per day (MMCFd).

Based on announced plans, the researcher assumes that two compression and looping expansions on Kern River Pipeline in 2010 and 2011 will increase capacity on Kern's mainline by a total of 411 MMCFd. These expansions are concentrated on the northern half of Kern's system. While they will increase the amount of gas available to the California market, they will not directly increase capacity crossing the California / Nevada border.

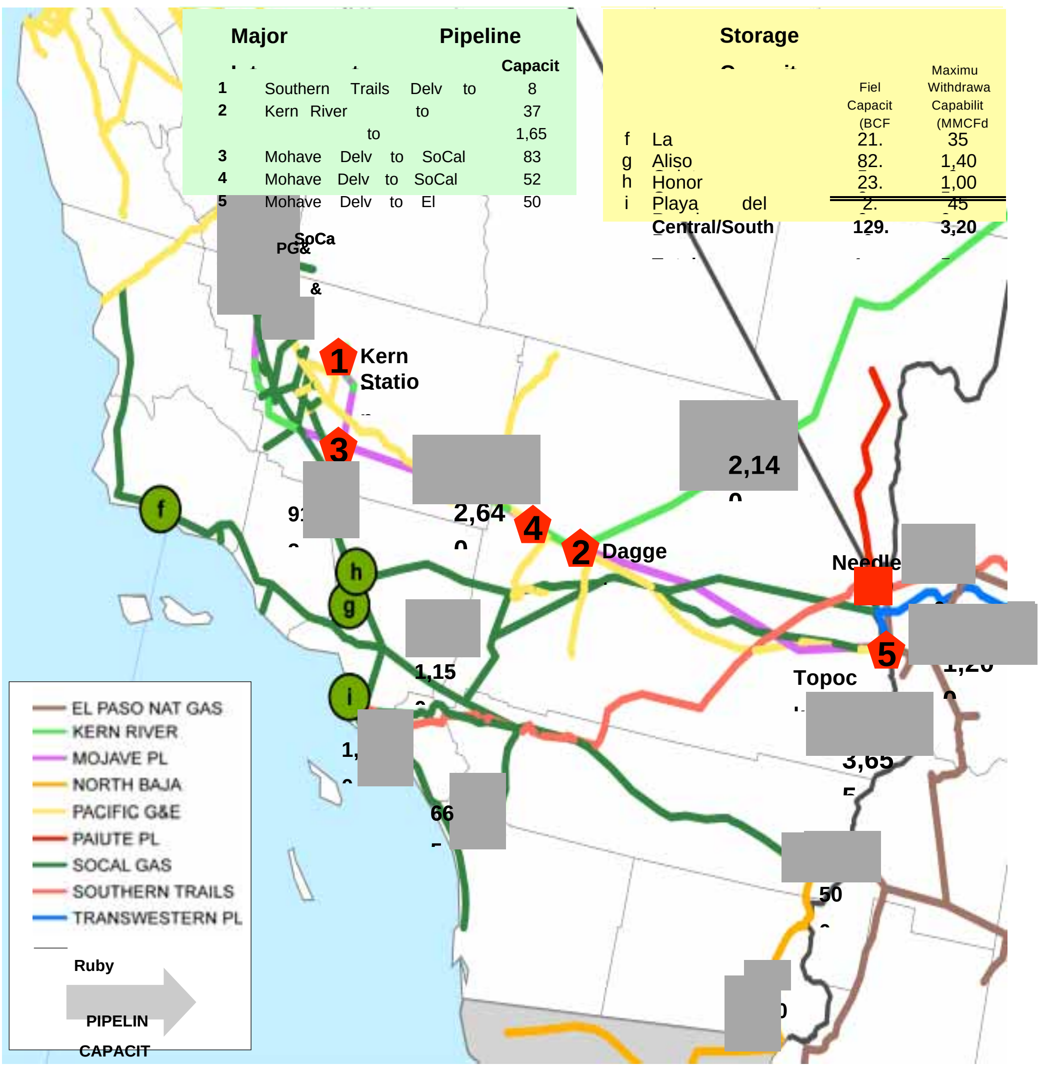

Figure 5: Central/Southern California Natural Gas Infrastructure in 2020

Source: ICF International, based on publicly available information

Though not technically part of Southern California's natural gas infrastructure, the Costa Azul LNG terminal in Baja, Mexico, will benefit the state indirectly. Costa Azul began operation in 2008 with a receipt capacity of 1 billion cubic feet per day (BCFd). Because of an apparent lack of firmly committed supplies, the researcher projects that LNG imports at Costa Azul are likely to be far less than the facility's capacity. In all the renewable cases, Costa Azul imports will average about 0.45 BCFd in 2020. While the facility is not expected to provide much gas for export to the United States, it still helps the California gas market by displacing demand for United States gas exports to Mexico.

In Northern California, Pacific Gas and Electric Company (PG&E) has over 2 BCFd of receipt capability at the Malin border crossing. The new Ruby Pipeline, scheduled to begin operation in 2011, will provide an additional 1.3 BCFd of pipeline capacity from Opal to Malin. A planned 42-inch line connecting Ruby to PG&E will provide additional capacity crossing the California / Oregon border, but at this time there are no publicly announced plans for additional capacity expansions on PG&E's system.

There are also two new storage fields and one field expansion planned by 2011 for Northern California. Sacramento Natural Gas Storage is scheduled to begin operation in 2010 with a working gas capacity of 7 BCF and maximum withdrawal capacity of 200 MMCFd. Gill Ranch is scheduled to begin operation in 2011 with a working gas capacity of 20 BCF and maximum withdrawal capacity of 300 MMCFd. Kirby Hills is scheduled to expand its working gas capacity by 6.5 BCF to 12 BCF in 2011; maximum withdrawal capacity will increase from 50 to 100 MMCFd. Including these expansions, Northern California's storage working gas capacity will total nearly 180 BCF by 2020, with a maximum withdrawal capability of over 3,200 MMCFd.

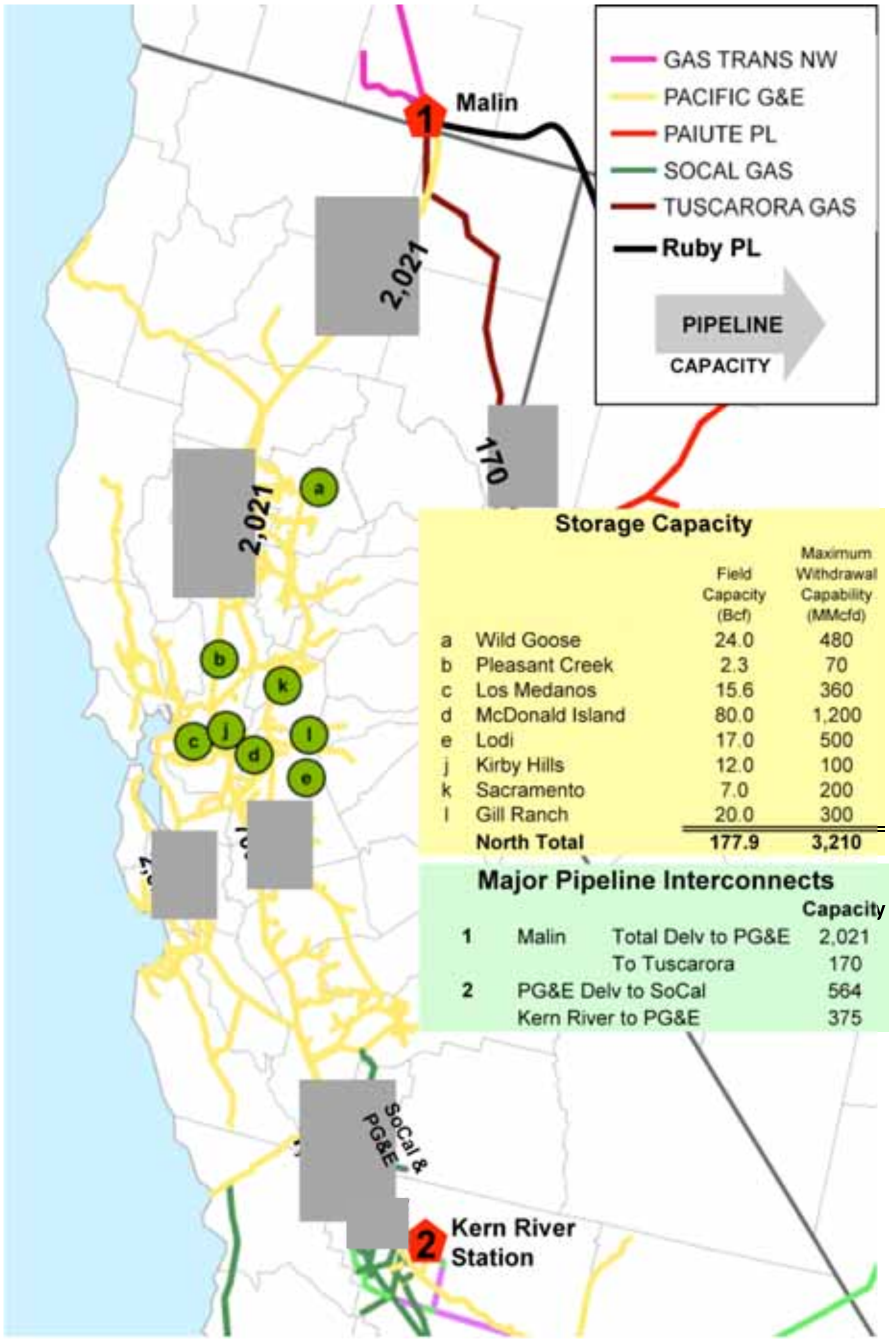

Figure 6: Northern California Natural Gas Infrastructure in 2020

Source: ICF International, based on publicly available information

4.0 Method for Constructing the Renewable Generation Cases

At the time this study was being conducted, the California Energy Commission had not developed any independent estimates for the seasonal patterns in RPS generation or potential reductions in RPS generation due to variability in weather. Therefore, the researcher developed its own estimates for the seasonality and potential reductions in RPS generation, which were applied to the 2020 RPS generation targets derived from the CPUC scenarios. The researcher provided its estimates to Energy Commission staff for review in March 2009, and there were no changes recommended.

4.1. Assumptions for Wind Generation

Monthly wind generation profiles are based on National Renewable Energy Laboratory (NREL) wind shape files that were provided to the researcher by Energy Commission staff. The NREL data includes hourly wind generation for each region of California for the years 2004, 2005, and 2006. This data has been used to determine the percentage of the total annual wind generation assigned in each month of the year to each area within California. The NREL wind shape data was also used to determine the distribution of daily wind generation for the month of January, which is the peak month for natural gas demand.

For purposes of determining where wind generation would be located, California is divided into three areas: Northern (above 36 degrees latitude), Central (between 34.75 degrees and 36 degrees latitude), and Southern (below 34.75 degrees latitude). These areas roughly correspond to both the GMM's California gas demand regions and regional division in the NREL wind data.

Under the Reference RPS scenarios (as used in Case 1), the expected annual wind generation in 2020 is 38,409 gigawatt-hours (GWh). Based on the NREL data, a portion of the annual generation was assigned to each month, as shown in Figure 7. For the state as a whole, monthly wind generation ranges from a high of 4 TWh (40% capacity utilization) in May to a low of 2.5 TWh (25% capacity utilization) in September.

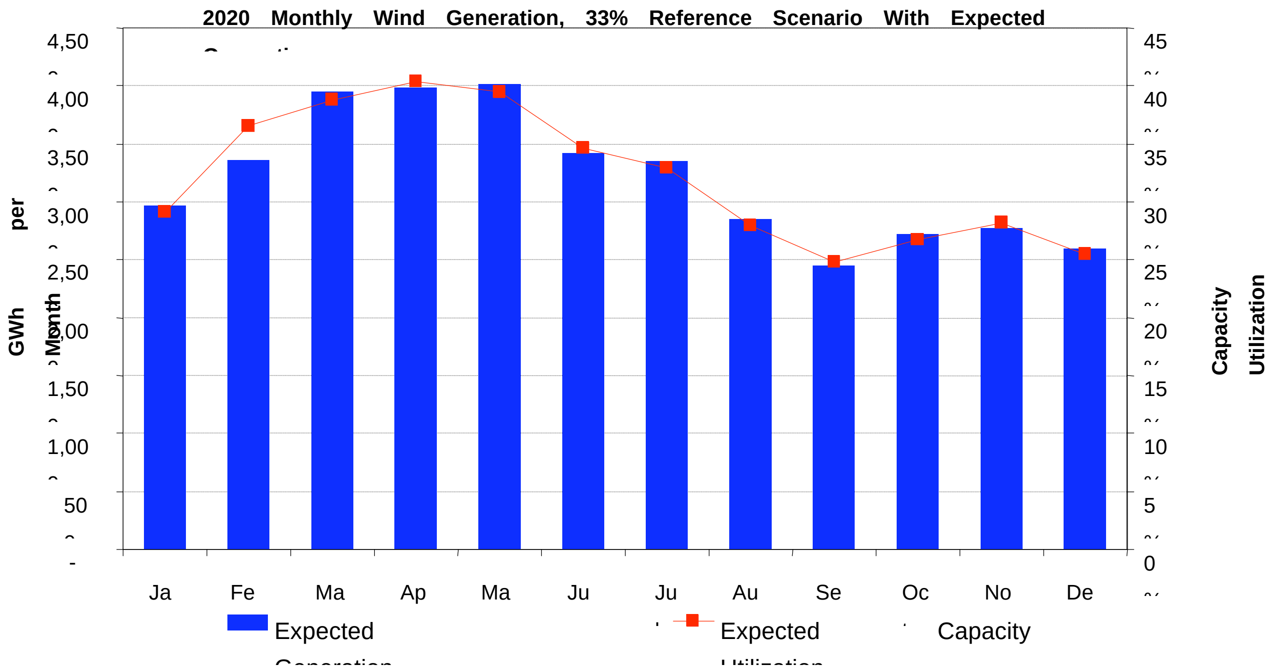

Figure 7: Example of Monthly Wind Generation in 2020

Source: ICF International

Daily wind generation in January 2020 is shown in Figure 8. For the month of January, daily generation ranges from a low of 30 GWh (9 percent capacity utilization) to a high of 153 GWh (47 percent capacity utilization). This is the range of daily values for the state as a whole, summed across all regions for each calendar day. Regionally, daily capacity utilization for January ranges from a low of 6 percent to a high of 57 percent.

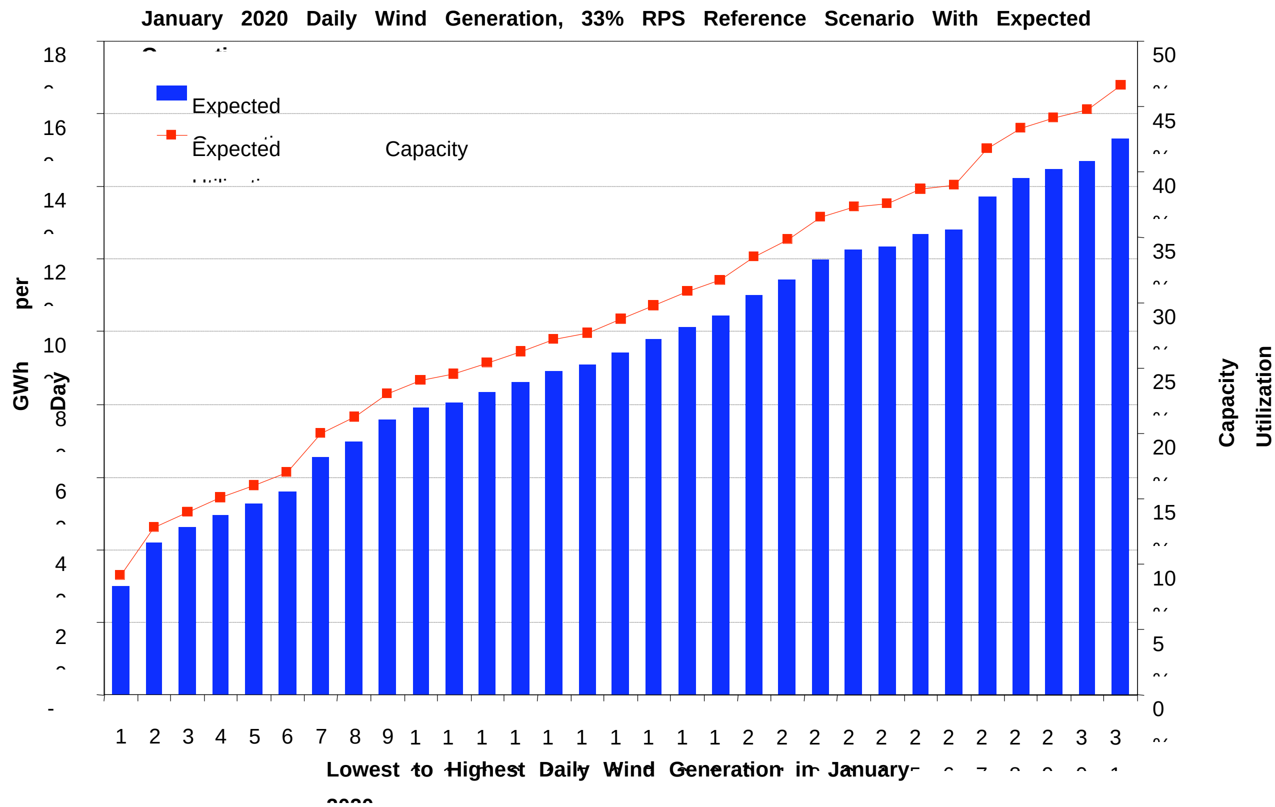

Figure 8: Example of Daily Wind Generation in 2020
Source: ICF International

Estimates for reduced wind generation are based on 20 to 30 years[5] of daily average wind speed data from the National Oceanic and Atmospheric Administration's (NOAA) National Climate Data Center from 12 weather stations throughout the state (six in Northern California, two in Central California, and four in Southern California). For each weather station, NOAA reports average daily wind speed, to which the researcher applied a wind power function to arrive at estimated potential generation for turbines located in that area of California.[6]

To estimate what the generation would be in a low wind year, the researcher summed the potential wind generation across all areas of the state for each year of historic data and picked the lowest coincidental historical year. The researcher chose this approach, rather than summing minimum levels of generation from different years for each area would exaggerate the degree of variability in generation, since low average wind speeds in one area of the state may be offset by higher wind speeds in another. Based on the historical wind speed data, the

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[5] The number of years of data available varies by weather station.

[6] Since the weather station anemometers are usually at a height of only 10 meters above the surrounding terrain, ICF applied an adjustment factor of 1.4 to the reported wind speed to arrive at an estimated wind speed at 100 meters, which is a typical hub height for a large wind turbine.

researcher estimated that in a low wind year, total annual wind generation could be as much as 24 percent below the expected annual generation.

An example of the reduced level of wind generation used for the Reference Scenario with Reduced Generation (Case 3) is shown in Figure 9. For the year in total, wind generation in the reduced case is 24 percent below expected level. July has the greatest reduction in wind generation, with the estimated low being 37 percent (or about 1,200 GWh) below the expected level of generation. In January, wind generation in the reduced case is 25 percent below the expected level of generation.

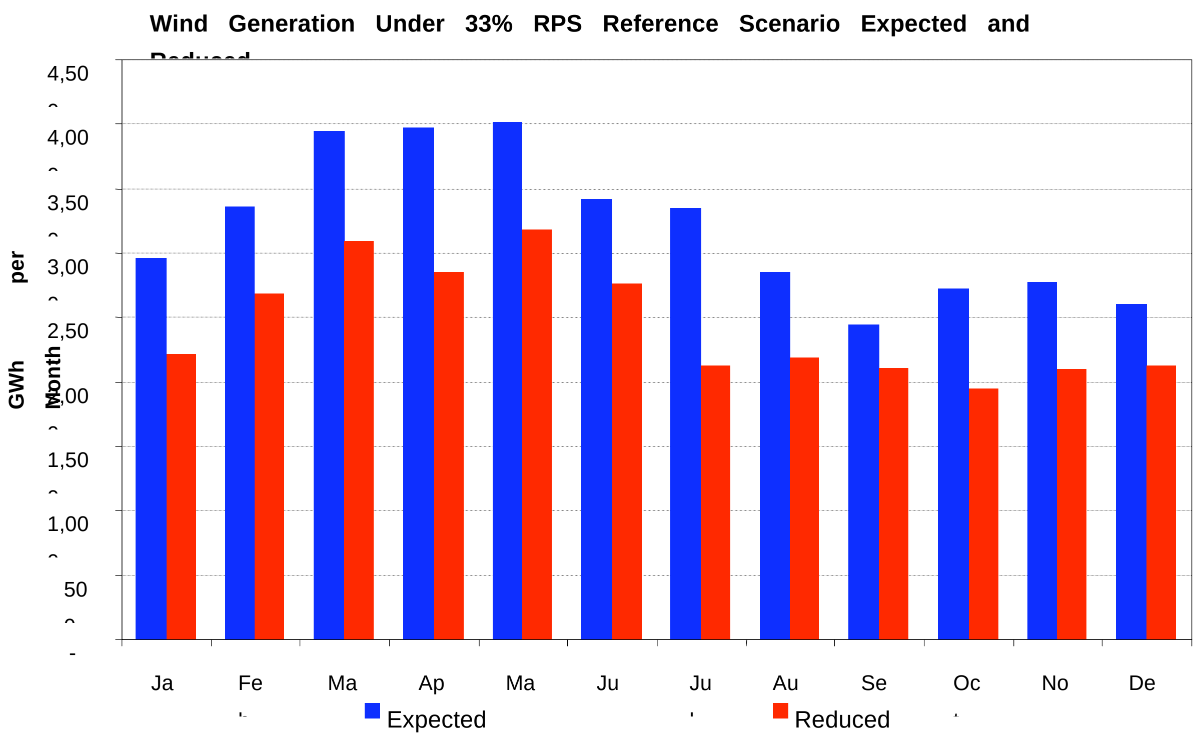

Figure 9: Example of Expected Versus Reduced Monthly Wind Generation
Source: ICF International

To arrive at reduced daily generation values for January, the researcher applied the percentage reduction in monthly generation (25 percent) to all days of the month as shown in Figure 10. Under the 33% Reference Scenario with Reduced Generation (Case 3), wind generation is only 20 GWh on the lowest wind generation day in January. When running the Reduced Generation cases, the researcher assumed a "stress" scenario, in which the lowest wind generation day in January occurred on the highest gas demand day in January. This increased the projected peak day gas demand during the highest gas demand month of the year.

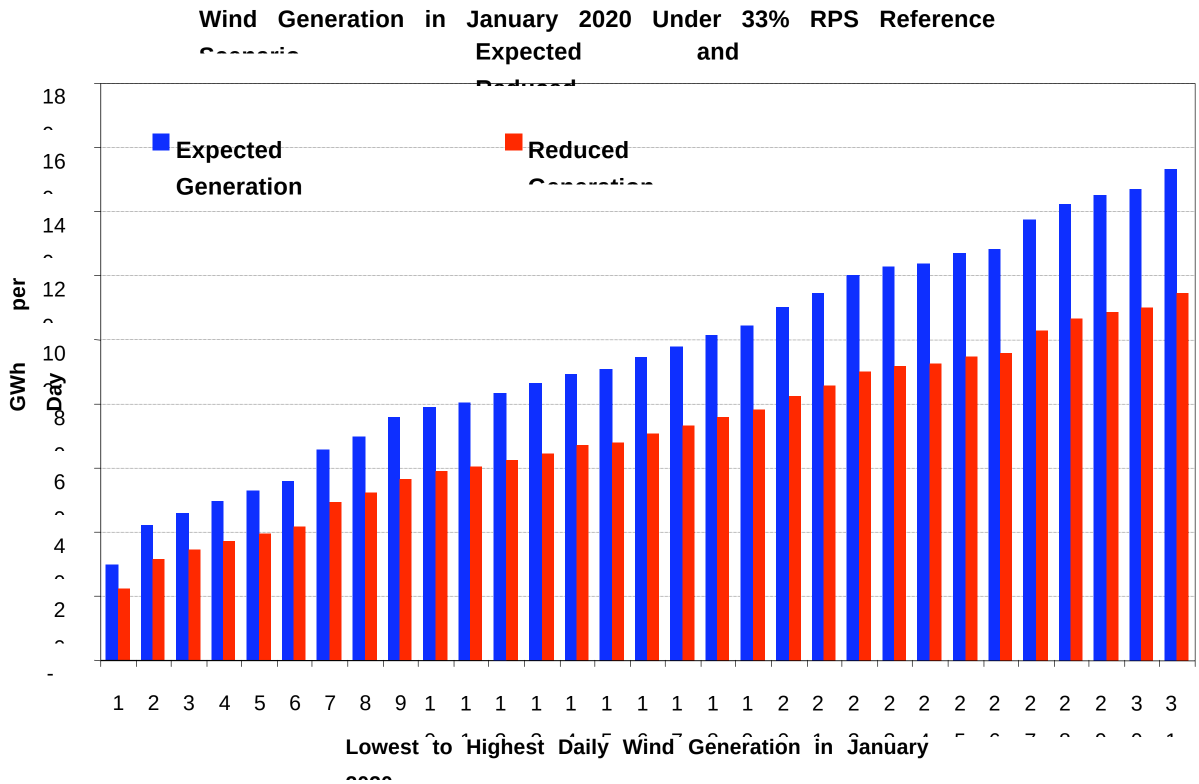

Figure 10: Example of Expected Versus Reduced Daily Wind Generation
Source: ICF International

4.2. Assumptions for Solar Generation

Assumptions for solar generation were based on 30 years of NREL data on solar radiation for six weather stations in Southern California.[7] The NREL data reports average daily solar radiation each month for 1961 to 1990; it does not include any data on daily variability within each month. Since the vast majority of California's solar resource is located below 34.75 degrees latitude, for modeling purposes the researcher assumed all solar generation is located in Southern California.

This data has been used to determine how much of the total annual generation should be assigned to each month of the year and the potential reductions in solar generation. Solar thermal and PV generation are assumed to have the same seasonal pattern and variability in generation. Minimum generation levels are based on the observed annual minimums in the historical solar radiation data across all six weather stations. The daily generation profile for January 2020 is based on the assumption that solar generation is distributed normally within the month.

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[7] National Solar Radiation Data Base (1961-1990), prepared by the National Renewable Energy Laboratory, 1617 Cole Blvd., Golden, Colorado, 80401.

Seasonally, California's solar generation potential is typically highest in the summer and lowest in winter, as shown in Figure 11. In Case 1 (Reference 33% RPS scenario with expected generation), monthly solar generation ranges from a high of 2.7 TWh (33 percent capacity utilization) to a low of 1.5 TWh (18 percent capacity utilization). Since the authors have assumed all solar generation is located in Southern California, this distribution applies to both the region and the state as a whole.

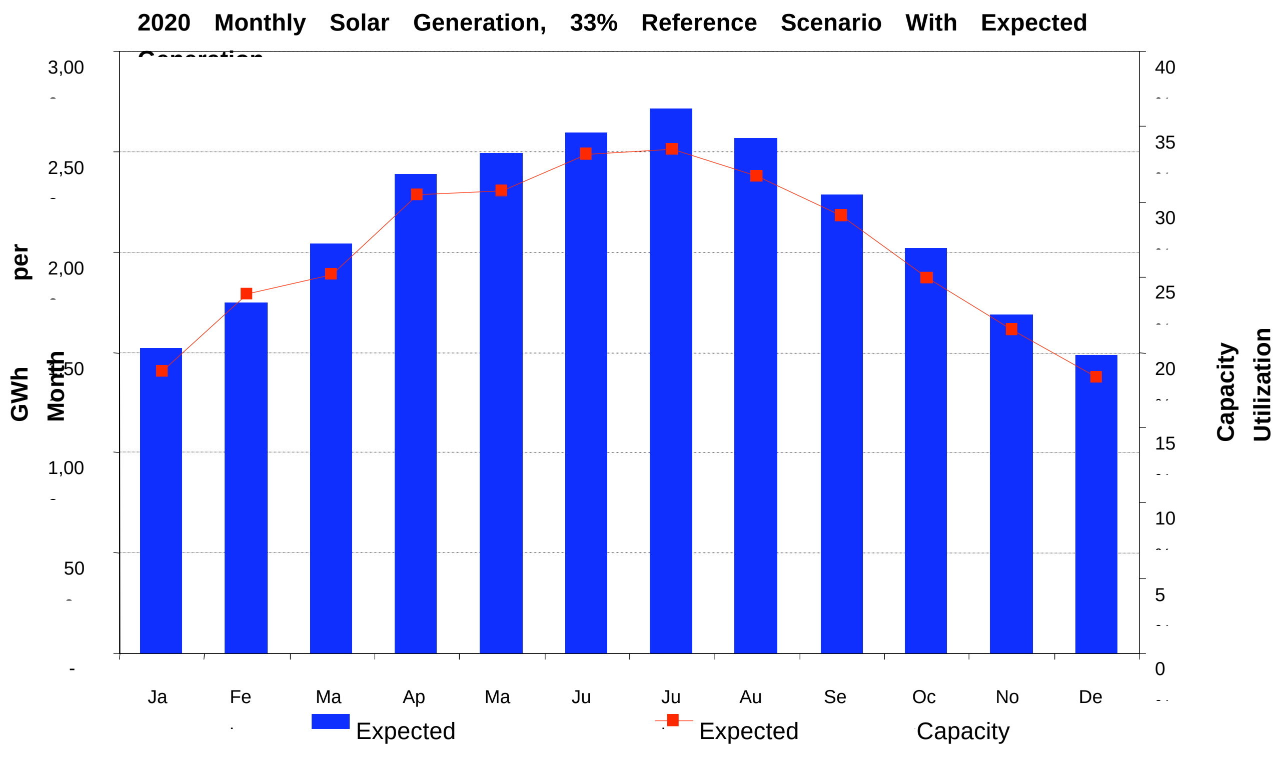


Figure 11: Example of Monthly Solar Generation in 2020
Source: ICF International

To arrive at a daily pattern for solar generation in January 2020, the researcher assumed that the total generation for January was distributed normally across the days of the month, as shown in Figure 12. As with the monthly variability, the researcher also assumed that solar thermal and PV have the same daily variability. For Case 1, daily solar generation in January 2020 is assumed to range from a low of 8 GWh (3 percent capacity utilization) to a high of 98 GWh (38 percent capacity utilization).

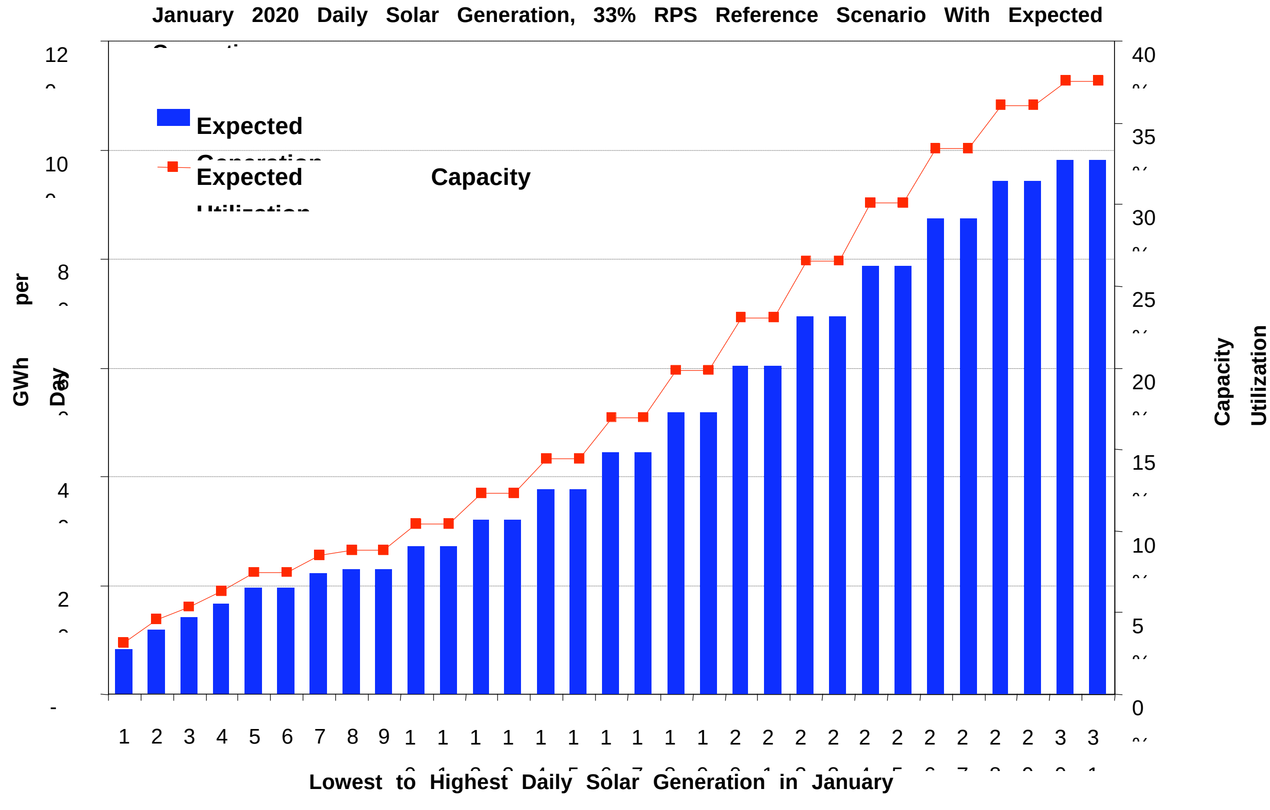


Figure 12: Example of Daily Solar Generation in 2020

Source: ICF International

Based on the historic solar radiation data, the researcher estimated that in a low solar year total annual solar generation could be as much as 8% below the expected annual generation. This is based on the lowest observed annual solar radiation levels across Southern California for the 30 years from 1961 through 1990. Solar generation is most variable in the winter months, with the estimated low for January being 13 percent below the expected level of generation, as shown in Figure 12. In the Reference Case with Reduced Generation (Case 3), solar generation in January 2020 is 200 GWh below the expected monthly total.

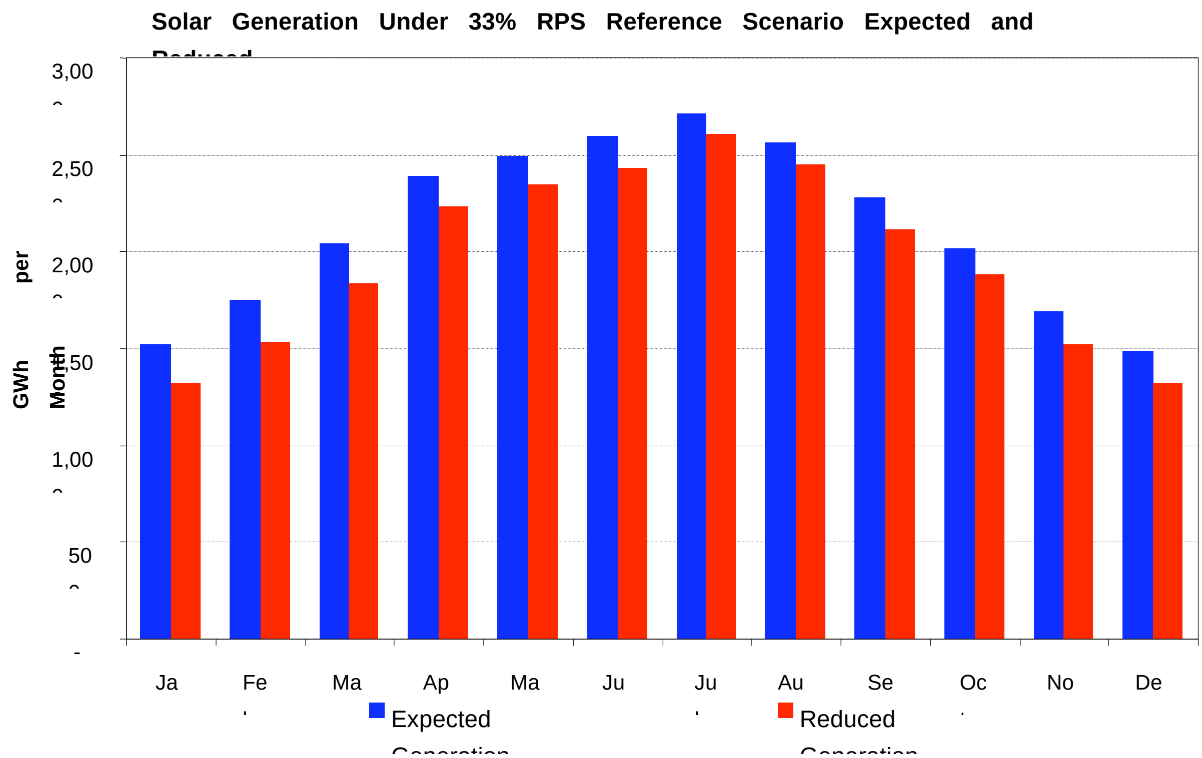


Figure 13: Example of Expected Versus Reduced Monthly Solar Generation
Source: ICF International

To arrive at the reduced daily solar generation values for January, the researcher applied the percentage reduction in monthly generation (13 percent) to all the days of the month, as shown in Figure: 14. In the Reference Case with Reduced Generation (Case 3), solar generation is only 7 GWh on the lowest day of January. For all the Reduced Generation cases, the researcher assumed a “stress” scenario, in which the lowest solar generation day in January occurs on the highest gas demand day in January. This increased the peak day gas demand during the highest gas demand month of the year.

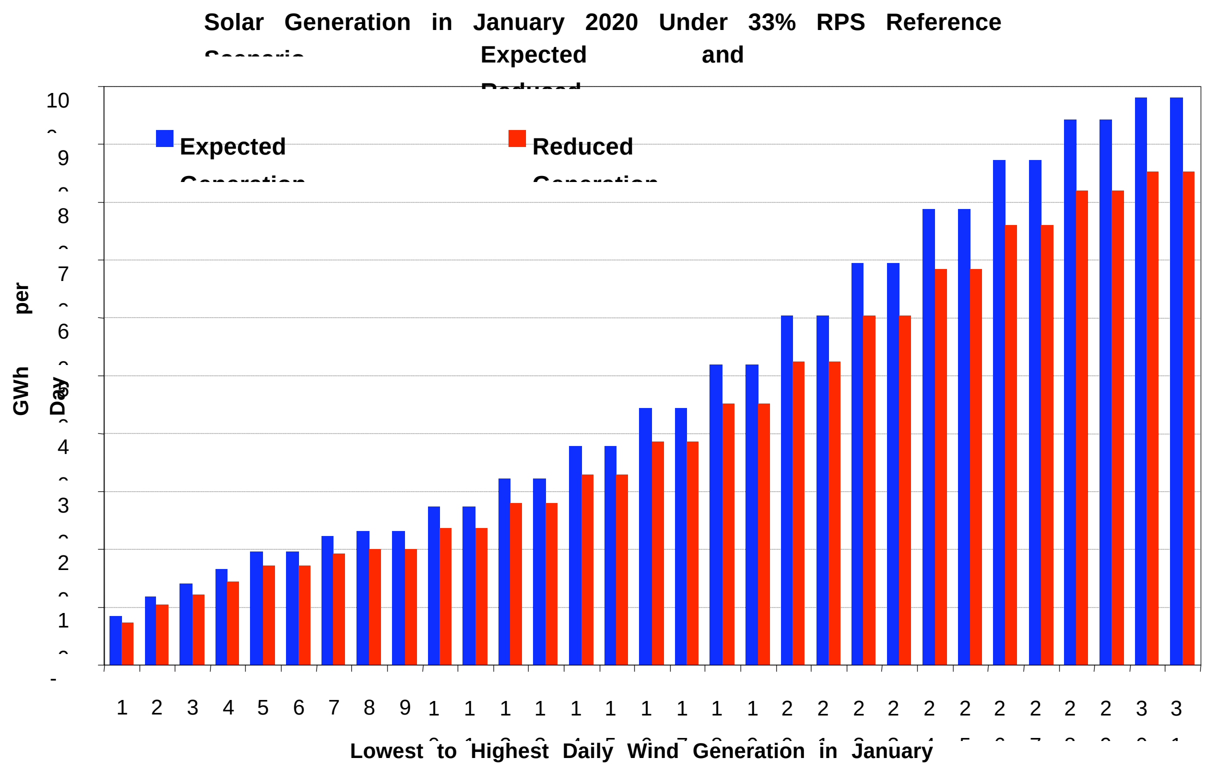


Figure: 14. Example of Expected Versus Reduced Daily Solar Generation
Source: ICF International

4.3. Assumptions for Biomass, Biogas, Geothermal, and Small Hydroelectric Generation

Unlike wind and solar technologies, biomass, biogas, and geothermal generation do not vary with changing weather conditions. Therefore, the researcher has assumed that the annual generation from these technologies is evenly distributed throughout the year and that there is no variation from the expected level of generation in the reduced generation cases.

As a simplifying assumption, the researcher has also kept small hydroelectric generation constant throughout the year. Small hydroelectric generation comprises only about 4 percent of the 2020 RPS generation total and less than 0.3 percent of the incremental increase in renewable generation through 2020. Variation in large hydroelectric generation, which makes up a much greater percentage of California's total electricity supply, is considered with the assumption of adverse temperature/hydroelectric conditions in Cases 2 through 5.

4.4. Assumed Reductions in Renewable Generation

For the reduced generation cases, total annual wind generation has been reduced by 24 percent and total annual solar generation has been reduced by 8 percent, compared to the expected values for each scenario, as shown in Table 3. As discussed above, biomass, biogas, geothermal, and small hydroelectric generation are all assumed to be constant. In total, annual RPS generation was reduced by between 10% and 12%, depending on the scenario.

Table 3: Reduced Renewable Generation by 2020 for Each 33% Scenario

	Reference		High Wind		Solar	
	GWh	% Reduction	GWh	% Reduction	GWh	% Reduction
Wind	29,352	-24%	37,119	-24%	28,108	-24%
Solar (PV and Thermal)	23,594	-8%	11,245	-8%	25,043	-8%
Biomass	8,746	0%	10,452	0%	8,806	0%
Biogas	2,078	0%	2,078	0%	2,078	0%
Geothermal	24,471	0%	25,985	0%	24,471	0%
Small Hydro	3,877	0%	3,861	0%	3,877	0%
Total RPS Generation	**92,119**	**-11%**	**90,741**	**-12%**	**92,383**	**-10%**

Source: ICF International

In all the reduced generation cases, total RPS generation is lowest in the winter, when wind and solar generation are generally at their lowest levels, as shown in Figure 15. Since generation from renewable technologies other than wind and solar are assumed to be constant, all the reductions in RPS generation are due to the assumed reductions in wind and solar generation.

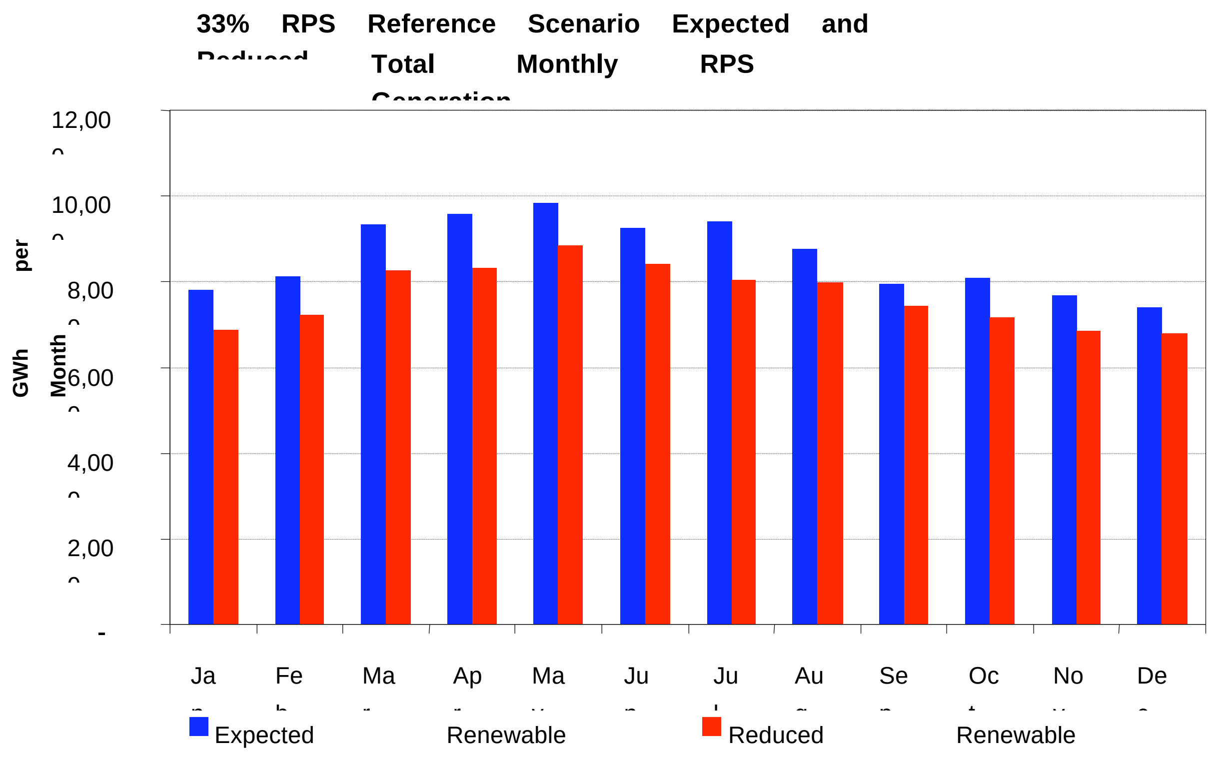


Figure 15: Example of Expected Versus Reduced Monthly Total RPS Generation
Source: ICF International

4.5. Seasonal Impacts of Reduced Renewable Generation on Natural Gas Demand and Infrastructure

In terms of the deficit in electricity generation, the potential for a reduction in renewables is greatest in the summer. In the reduced generation cases, RPS generation in July 2020 is down by 1,300 to 1,600 GWh (14 percent to 18 percent). Assuming this deficit is replaced entirely with gas-fired generation, this would increase gas demand for power generation by an average of 0.3 to 0.4 BCFd.

However, residential/commercial gas demand is much lower in the summer than in the winter. In Case 1 (Reference RPS with Expected Generation), residential/commercial is about 1.8 BCFd lower in July than in January. The normal variation in seasonal residential/commercial gas load is much greater than the potential variation caused by a reduction in renewable generation. The seasonality of gas storage also makes it easier to respond to increases in power generation gas demand in the summer. Natural gas is normally injected into storage in the summer. These injections could be avoided on peak summer days, and gas could even be withdrawn if needed to meet demand. Therefore, due to normal seasonal variation in residential/commercial gas demand and the seasonality of gas storage, reductions in renewable generation have less of an impact on California's gas infrastructure in the summer months.

In contrast, reductions in RPS generation have a much greater impact on gas pipeline loads and storage withdrawals in the winter months. Due to normal seasonal variations in wind and solar generation, expected levels of RPS generation are lowest in the winter months. Also, California gas demand peaks in January, due to increased residential and commercial loads. Therefore, any reductions in renewable generation in January add additional gas demand at a time when gas demand is already at its highest. This is why the authors have focused the daily gas load analysis on the January peak gas demand day.

4.6. Assumptions for Adverse Temperatures and Hydroelectric Generation

In Case 1, the researcher assumed that seasonal temperatures and hydroelectric generation are "normal" throughout the United States and Canada for all years of the projection. For temperatures, normal is defined as the average monthly heating and cooling degree days for the past 30 years (1979 to 2008). For hydroelectric generation, normal is the average monthly generation for the 25-year period 1980 to 2004. In the daily analysis, the pattern of peak month (January) temperatures is representative of average variability in January weather.

Cases 2 through 5 assume adverse temperatures (hotter summer and colder winter) and reduced hydroelectric generation in the years 2019 and 2020. This is done to test the robustness of California's gas infrastructure if the reductions in renewable generation occur during a year similar to the 2000/01 energy crisis, when gas demand was unusually high due to the adverse temperature and hydroelectric conditions. The assumptions for adverse temperatures and hydroelectric generation are based on our earlier analysis of the impact of temperature and hydroelectric generation on natural gas storage utilization in California. For this analysis, the researcher chose temperatures from 1957-1958 and hydroelectric generation from 2000-2001, which was the combination referred to as the "extreme" case in the temperature/hydro analysis. In the adverse temperature/hydro cases, the changes to weather and hydroelectric generation are applied through the United States and Canada.

For the daily analysis, the researcher has chosen a temperature pattern for January that included the coldest day in California from the past 30 years of daily temperature data. In the daily analysis for the Reduced Generation cases (Case 3 through 5), the researcher also placed the lowest renewable generation day on the coldest January day, which further increases gas demand and places additional stress on the natural gas infrastructure.

5.0 Case Results

This section details the results of the five renewable generation cases run by the researcher. For each case the researcher provides an overview of the gas demand projections annual, seasonally, and for the January peak gas demand day, as well as an analysis of how demand is met through pipeline imports and storage withdrawals.

5.1. Case 1: 33 Percent RPS Reference Scenario With Expected Generation and Normal Weather

5.1.1. Case Results Overview

Given normal weather and expected renewable generation output, California's demand for natural gas is expected to decline to 5.4 BCFd by 2020, a decrease of 900 MMCFd (Table 4). The majority of this decline is due to decreasing demand for natural gas in the power sector, where demand declines by 800 MMCFd through 2020. The decline in power sector gas demand is due to modest electric load growth coupled with the increase in renewable generation to meet the 33 percent RPS. The rest of the decline is in the residential sector, where increasing efficiency leads to a decline of 100 MMCFd by 2020. Commercial and industrial gas demands both remain relatively flat through 2020.

Table 4: California's Natural Gas Balance, Case 1

Bcfd	2008	2009	2010	2015	2019	2020	2008-20 Delta	2008-20 CAGR
Consumption	**6.29**	**5.58**	**5.69**	**5.66**	**5.44**	**5.39**	(0.9)	-1.3%
Residential	1.43	1.31	1.34	1.30	1.29	1.29	(0.1)	-0.8%
Commercial	0.67	0.66	0.66	0.65	0.65	0.66	(0.0)	-0.2%
Industrial	1.48	1.35	1.45	1.48	1.50	1.50	0.0	0.1%
Power Generation	2.58	2.13	2.11	2.10	1.86	1.81	(0.8)	-2.9%
Other	0.13	0.13	0.12	0.13	0.13	0.13	(0.0)	-0.4%
Pipeline Exports	**0.07**	**0.08**	**0.10**	**0.03**	**0.09**	**0.09**	0.0	1.6%
To Northern Nevada	0.07	0.08	0.10	0.02	0.02	0.02	(0.1)	-10.4%
To Mexico	-	-	-	0.02	0.07	0.07	0.1	n/a
Production	**0.88**	**0.87**	**0.84**	**0.83**	**0.85**	**0.85**	(0.0)	-0.4%
Pipeline Imports	**5.61**	**4.94**	**5.03**	**4.91**	**4.72**	**4.67**	(0.9)	-1.5%
via Southern Nevada (Kern River)	1.54	1.52	1.53	1.87	1.87	1.87	0.3	1.7%
via Arizona (El Paso, Transwestern)	2.82	1.93	2.01	1.84	1.60	1.58	(1.2)	-4.7%
via Malin	1.23	1.48	1.45	1.18	1.25	1.21	(0.0)	-0.2%
via Mexico (Costa Azul LNG)	0.02	-	0.04	0.02	0.00	0.01	(0.0)	-7.0%
Storage Net Injections / (Withdrawals)	**0.02**	**0.09**	**0.02**	**-**	**-**	**-**	(0.0)	-100.0%
Balancing Item	**0.11**	**0.07**	**0.06**	**0.05**	**0.04**	**0.04**	(0.1)	-8.8%

Source: ICF International

Natural gas production in California remains relatively flat through 2020, decreasing by about 30 MMCFd during the period. As a result, imports of natural gas to California decrease by about the same amount as the decrease in gas demand. Most of the declines are on the El Paso Natural Gas and Transwestern Pipeline systems, which together are down by roughly 1.2 BCFd from 2008 to 2020. Imports along Kern River Pipeline in Central California increase by about 300 MMCFd through 2020, driven by growth in gas production in the Rockies and increased pipeline capacity on the Kern River system. Imports at the Malin Interchange and Mexico remain relatively flat throughout the projection period.

As in most of the rest of the United States, California's peak gas demand month is January (Figure 16). In Case 1, which has normal weather and expected renewable generation, California consumes an average of 6.9 BCFd in January 2020. California's electricity demand peaks in July and August, which creates a secondary peak in gas demand due to increased demand in the power sector. However, the summer gas demand peak is much lower than the winter peak.

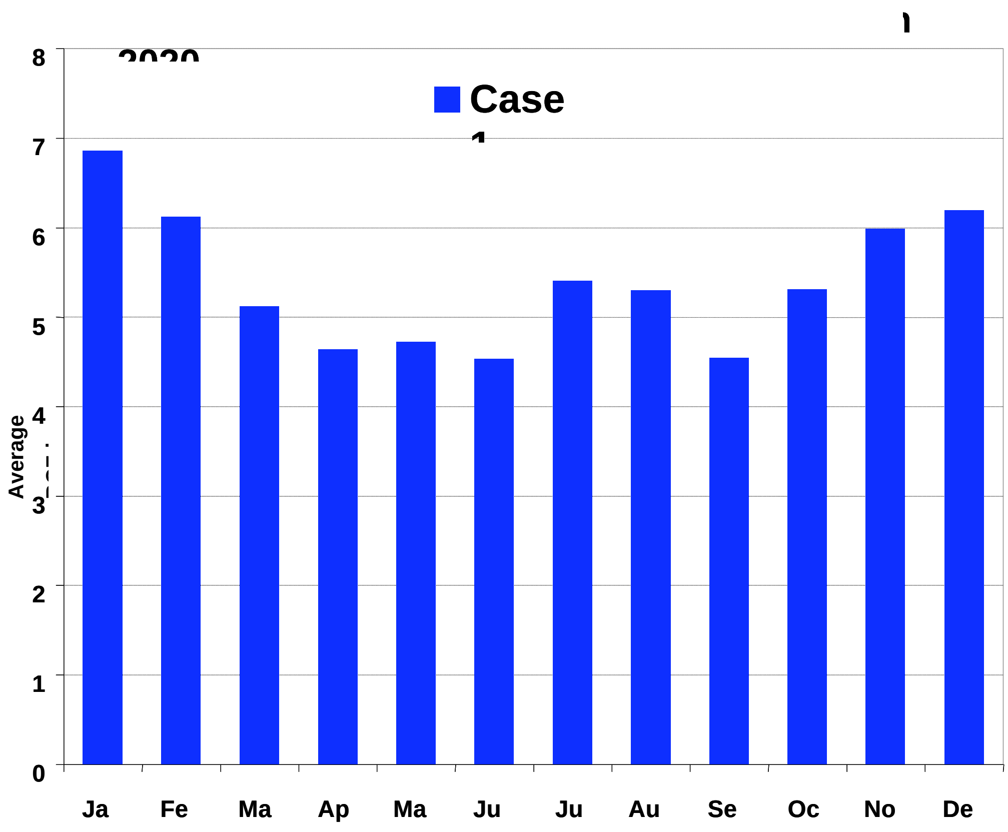


Figure 16: California Monthly Gas Consumption in 2020, Case 1
Source: ICF International

Included the storage capacity additions noted in Section 3.1.3, California's total storage working gas capacity is projected to be in excess of 300 BCF by 2020. Under normal weather and hydroelectric conditions, the working gas fill level at the end of March 2020 (the end of the storage withdrawal season) is about 120 BCF, or nearly 40 percent of available capacity (Figure 17). To put this into historical perspective, during the 2000-01 Energy Crisis in California, working gas levels dropped down to around 60 BCF in February 2001 out of a total capacity of about 240 BCF, or roughly 24 percent of working gas capacity.

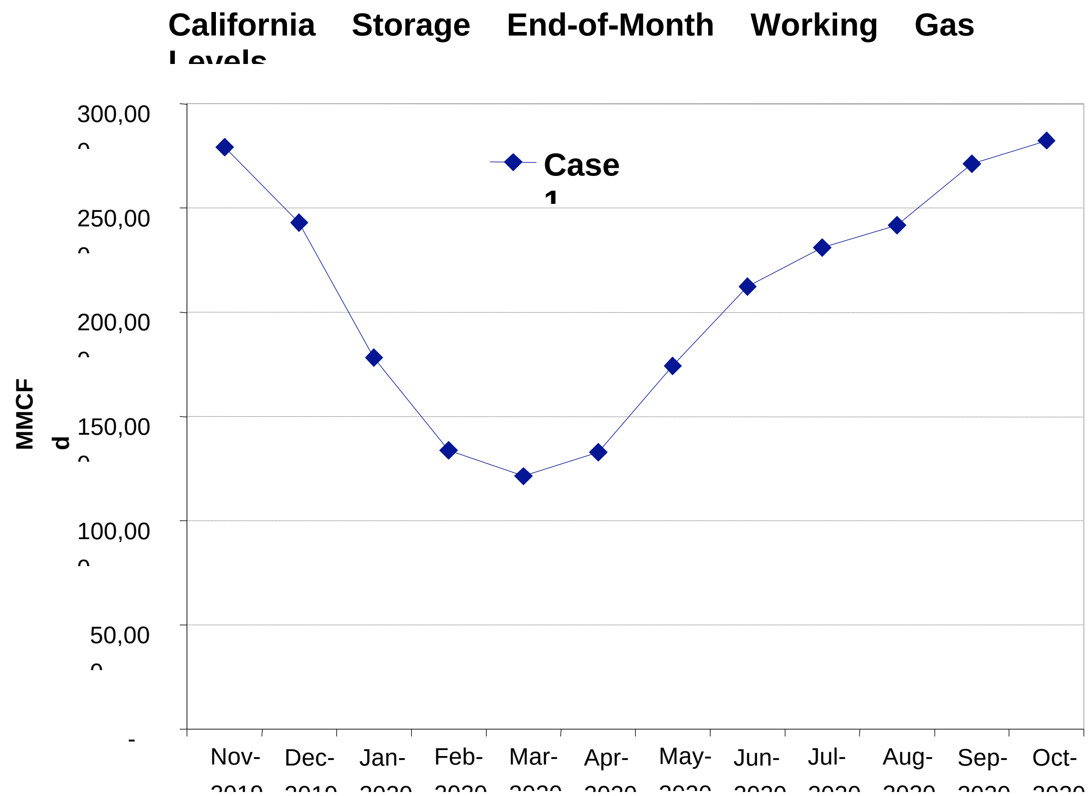


Figure 17: California Storage End-of-Month Working Gas Levels, Case 1
Source: ICF International

5.1.2. Peak Analysis

In Case 1, January 2020 peak gas demand day is projected to be 8.2 BCF. The majority of the demand is in the Residential/Commercial sectors, which accounts for roughly 4.2 BCF, or about 50 percent, of total demand for the day (Figure 18). The power sector is the next largest sector, accounting for 2.5 BCF, or around 30 percent. The industrial sector accounts for only 1.6 BCF, or about 20 percent, of peak day consumption.

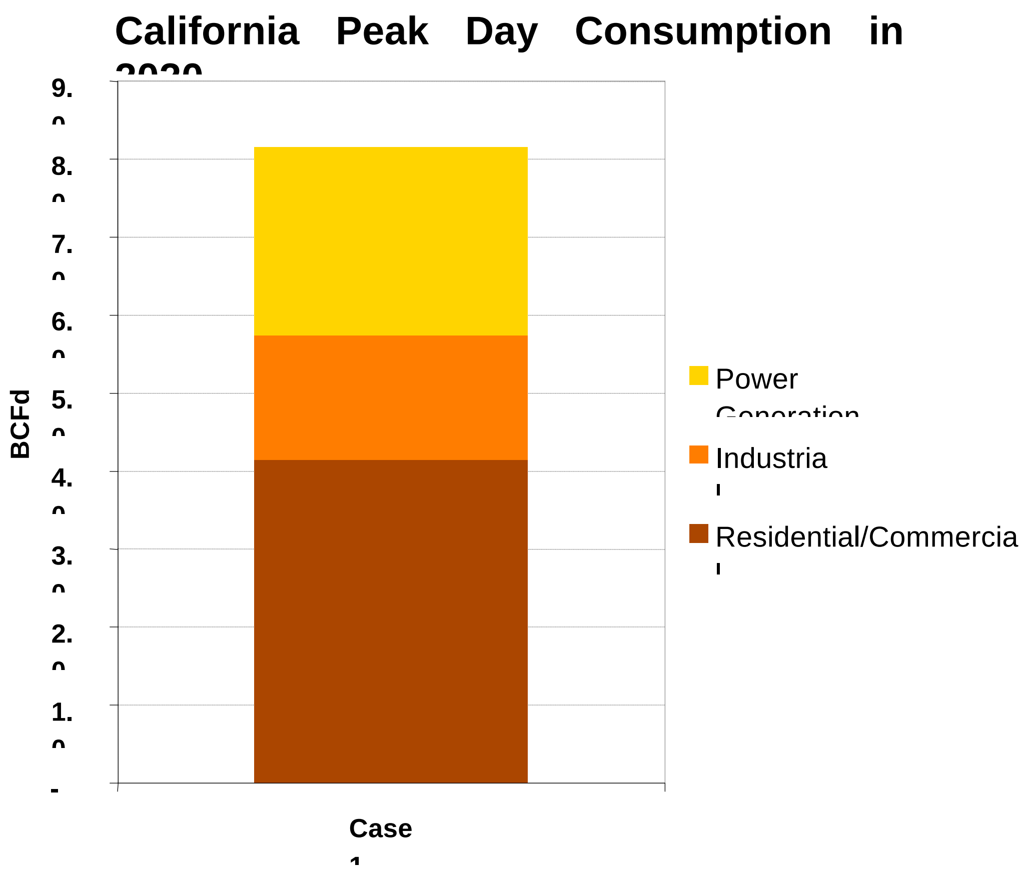
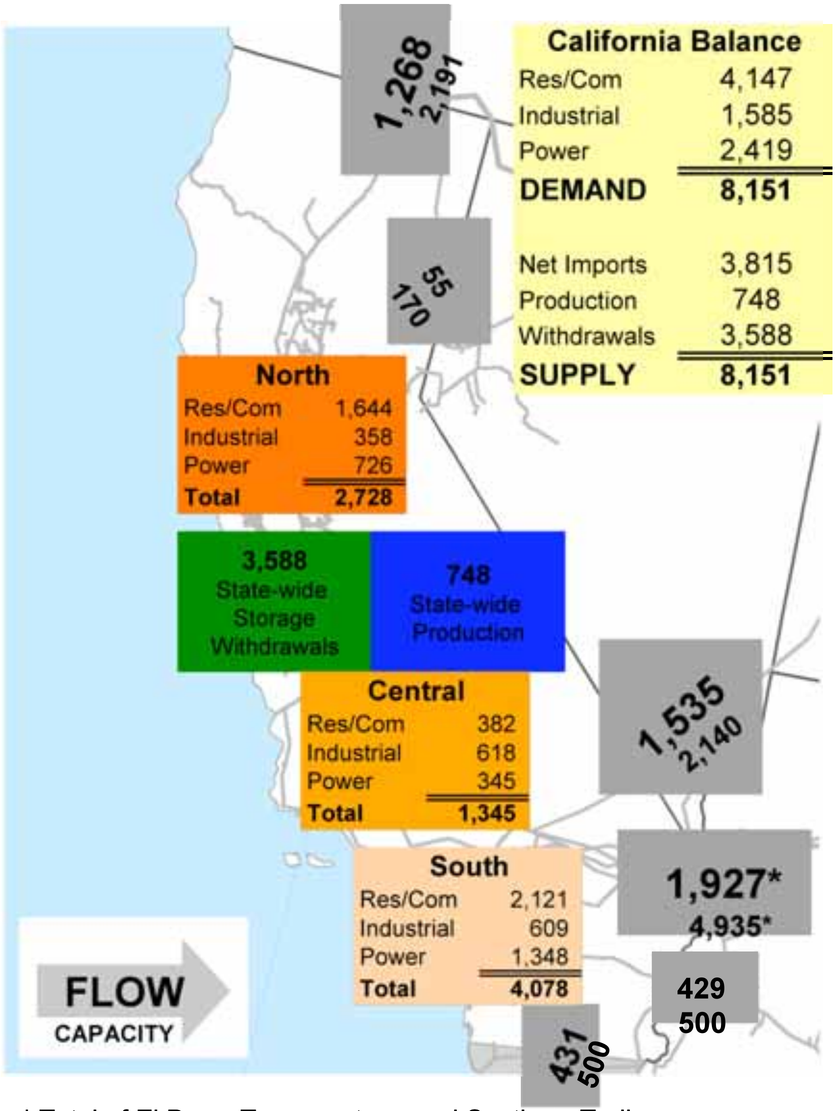


Figure 18: California January 2020 Peak Day Gas Consumption, Case 1
Source: ICF International

Most of the state's peak day demand is in Southern California. Given normal weather and expected renewable generation, Southern California consumes almost 4.1 BCF of natural gas, or close to 50 percent of total peak daily demand for the State (Figure 19). Northern California is the second highest demand area, consuming over 2.7 BCF of gas, or roughly 33 percent of peak day demand. Central California demand is only about 1.3 BCF on the peak demand day.

California's peak day demand is met primarily with a combination of pipeline imports (3.8 BCF) and natural gas storage withdrawals (3.6 BCF). The balance, about 0.8 BCF, is met with in-state gas production.



* Total of El Paso, Transwestern, and Southern Trails

Figure 19: January 2020 Peak Day Balance (MMCFd), Case 1
Source: ICF International

In Southern and Central California, natural gas pipelines do not appear to be a constraining factor on supply in Case 1. Of the three major pipelines entering the area – Kern River, Transwestern, and El Paso – the highest load factor observed is on Kern River, which has a load factor of just over 70 percent on the 2020 peak demand day. In total, importing pipelines to the area have unused capacity of over 3.6 BCF (Figure 20). Storage is also similarly unconstrained. On the peak demand day, the four storage fields in Southern and Central California withdrawal a total of around 2.1 BCF, or about 64 percent of total 3.2 BCF of withdrawal capability of the four fields.

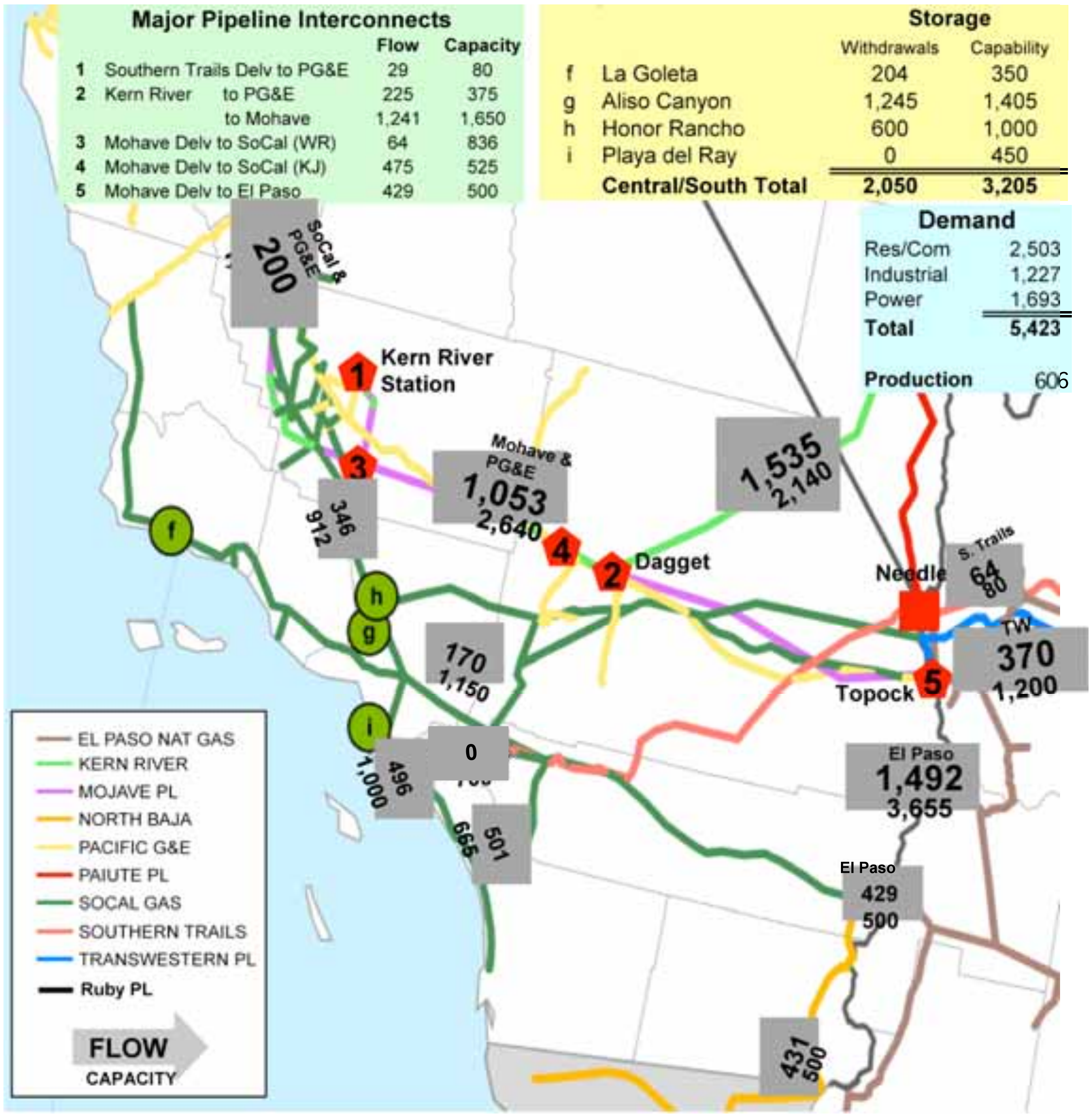


Figure 20: January 2020 Peak Day Flows in Southern/Central California (MMCFd), Case 1

Source: ICF International

Total demand in Southern and Central California on an average January day is about 830 MMCF lower than on a peak day. All of incremental demand is met by regional storage. Close to 950 MMCF of additional gas is withdrawn from regional storage on a peak day; about 2.1 BCF is withdrawn from storage on a peak day while only about 1.1 BCF is withdrawn on an average day. On the other hand, peak day pipeline imports of natural gas are almost the same, with about 140 MMCF less gas being imported than on an average day. Similarly to imports, pipeline exports on a peak day are about the same as on an average day, with a negligible amount of additional gas being export to Northern California on a peak day to help fill demand in that region (Figure 20).

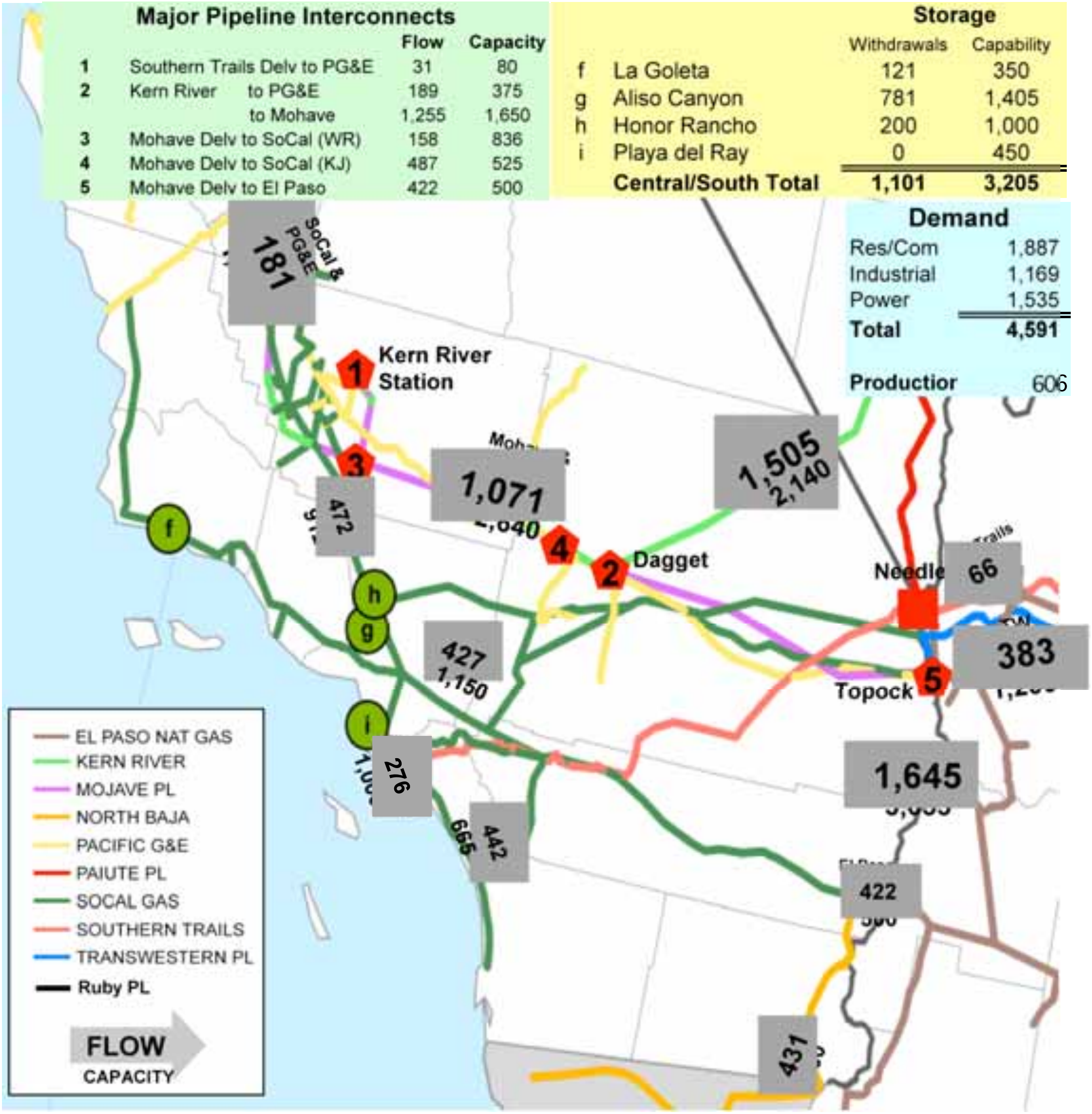


Figure 21: January 2020 Average Flows in Southern/Central California (MMCFd), Case 1

Source: ICF International

The peak day flows on PG&E south of Malin is 1.2 BCF, or less than 60 percent of the system's capacity (Figure 22). In-state deliveries to Northern California from Southern and Central California are relatively small at 200 MMCF, or about 7 percent of total demand for the day. Storage fields in the area are also unconstrained on the peak day, at less than 50 percent of the total storage withdrawal capability in Northern California.

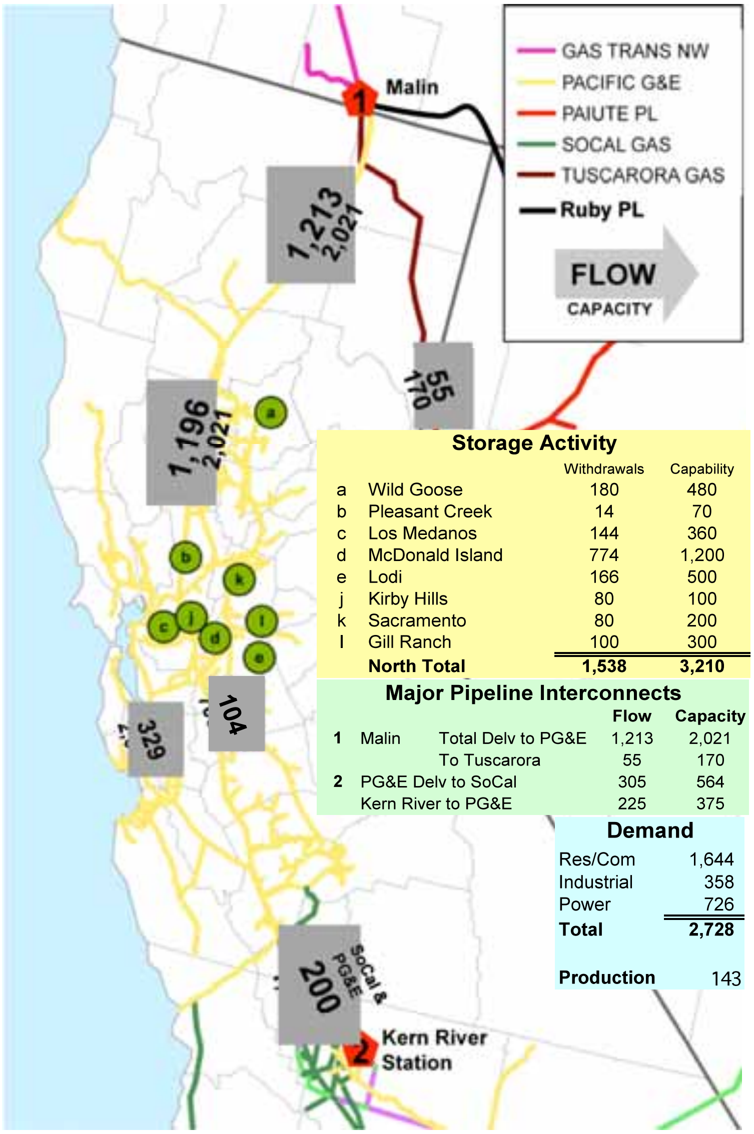


Figure 22: January 2020 Peak Day Flows in Northern California (MMCFd), Case 1
Source ICF International

On a peak January demand day, Northern California consumes about 490 MMCF more than on an average day. As in Southern and Central California, the entirety of this incremental demand is met by increased storage withdrawals. Compared to the peak day, storage withdrawals on an average January day are roughly 550 MMCF lower (Figure 23). Intrastate pipeline imports from Southern and Central California are slightly higher on a peak day, but this increase is offset by slightly lower imports at Malin.

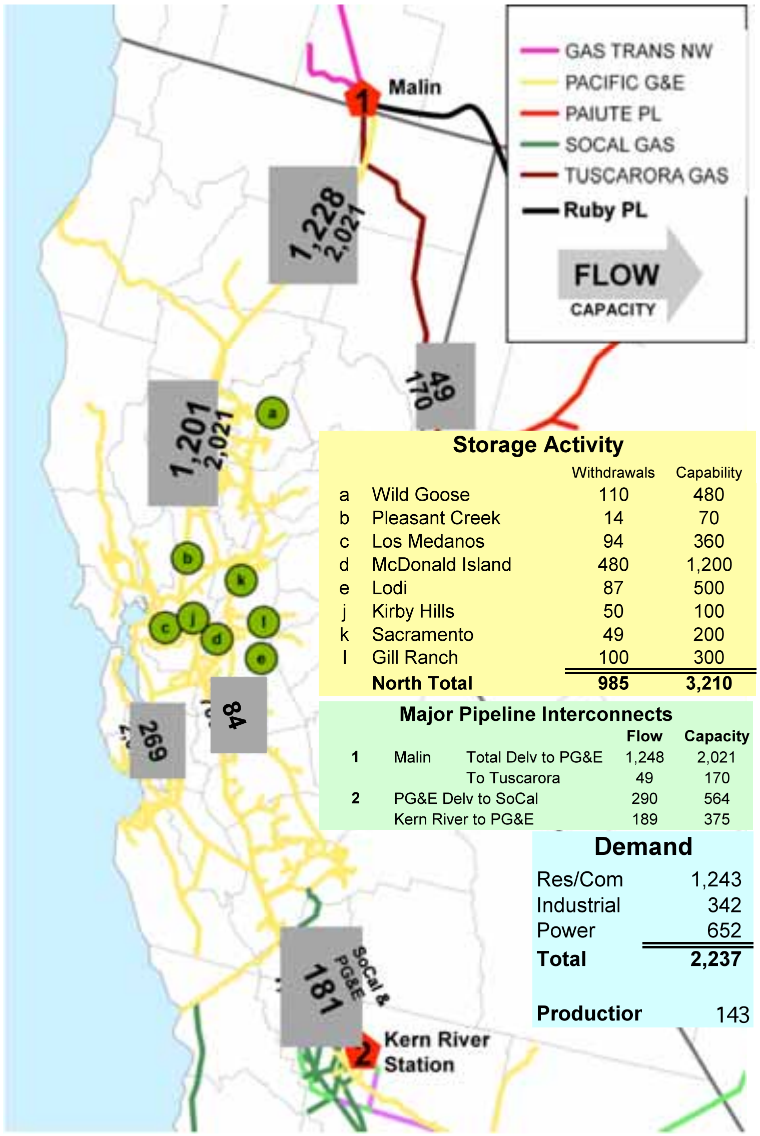


Figure 23: January 2020 Average Flows in Northern California (MMCFd), Case 1

Source: ICF International

5.2. Case 2: 33 Percent RPS Reference Scenario With Expected Generation and Adverse Weather

5.2.1. Case Results Overview

Case 2 adds adverse temperatures and reduced hydroelectric generation in the year 2020, but still assumes that renewable generation is at expected levels. In Case 2, average annual gas consumption in 2020 is 6.1 BCFd, or about 670 MMCFd higher than in Case 1 (Table 5). However, despite the addition of adverse temperature / hydroelectric conditions in Case 2, the projected gas demand in the year 2020 is still lower than the 2008 demand by almost 240 MMCFd.

Table 5: California's Natural Gas Balance, Case 2 vs. Case 1

BCF	2019 Case	2019 Delta vs Case	2020 Case	2020 Delta vs Case
Consumption	**5.6**	***0.1***	**6.0**	***0.6***
Residential	1.3	*0.0*	1.2	*(0.05)*
Commercial	0.6	*0.0*	0.6	*(0.01)*
Industrial	1.5	*(0.00)*	1.4	*(0.02)*
Power Generation	2.0	*0.1*	2.5	*0.7*
Other	0.1	*0.0*	0.1	*0.0*
Pipeline Exports	**0.0**	***(0.01)***	**0.0**	***(0.03)***
To Northern Nevada	0.0	-	0.0	*(0.01)*
To Mexico	0.0	*(0.01)*	0.0	*(0.02)*
Production	**0.8**	***0.0***	**0.8**	***0.0***
Pipeline Imports	**4.8**	***0.1***	**5.3**	***0.6***
Via Southern Nevada (Kern River)	1.8	*(0.02)*	1.7	*(0.09)*
Via Arizona (El Paso, Transwestern)	1.7	*0.1*	2.1	*0.5*
Via Malin	1.2	*0.0*	1.3	*0.1*
Via Mexico (Costa Azul LNG)	0.0	*0.0*	0.0	*0.0*
Storage Net Injections / (Withdrawals)	**-**		**-**	*0*
Balancing Item	**0.0**	***0.0***	**0.0**	***0.0***

Source: ICF International

Increased flows on the El Paso and Transwestern pipelines meet most of the incremental demand increase in Case 2. In total, flows on these two pipelines are up by 530 MMCFd, compared to Case 1. In northern California, imports at Malin are up by 180 MMCFd compared to Case 1.

Figure 24 shows a comparison of average monthly demand in California between Case 1 and Case 2. With the exception of December, monthly average gas demand in California is higher under adverse weather conditions by between 300 MMCFd to 1500 MMCFd. In January (the peak gas demand month), average daily demand is around 7.4 BCFd, an increase of about 500 MMCFd over Case 1. A combination of hot summer weather and poor hydroelectric generation leads to an increase in August demand of over 1 BCFd, but the average daily gas demand in August is still about 1 BCFd lower than in January.

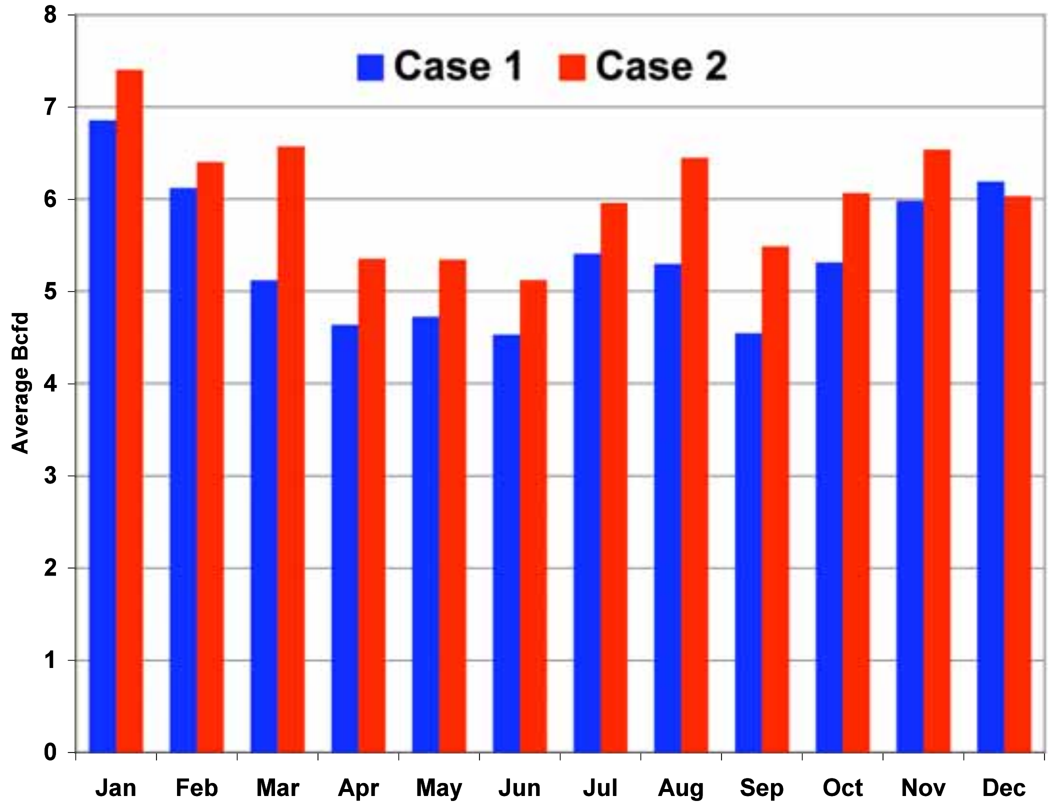


Figure 24: California Monthly Gas Consumption in 2020, Case 2 vs. Case 1
Source: ICF International

Despite the adverse temperature and hydroelectric generation conditions in Case 2, monthly storage withdrawals through January 2020 are not significantly different than in Case 1. As the withdrawal season continues, though, California relies more heavily upon storage to meet the increased demand. By the end of March, storage working gas levels are down to 70 BCF, or roughly 22 percent of the State's total storage capacity by 2020. Still, there is sufficient pipeline capacity and available gas supplies to allow California's storage fields to refill to the same level as in Case 1 by October 2020 (the beginning of the next storage withdrawal season)(Figure 24).

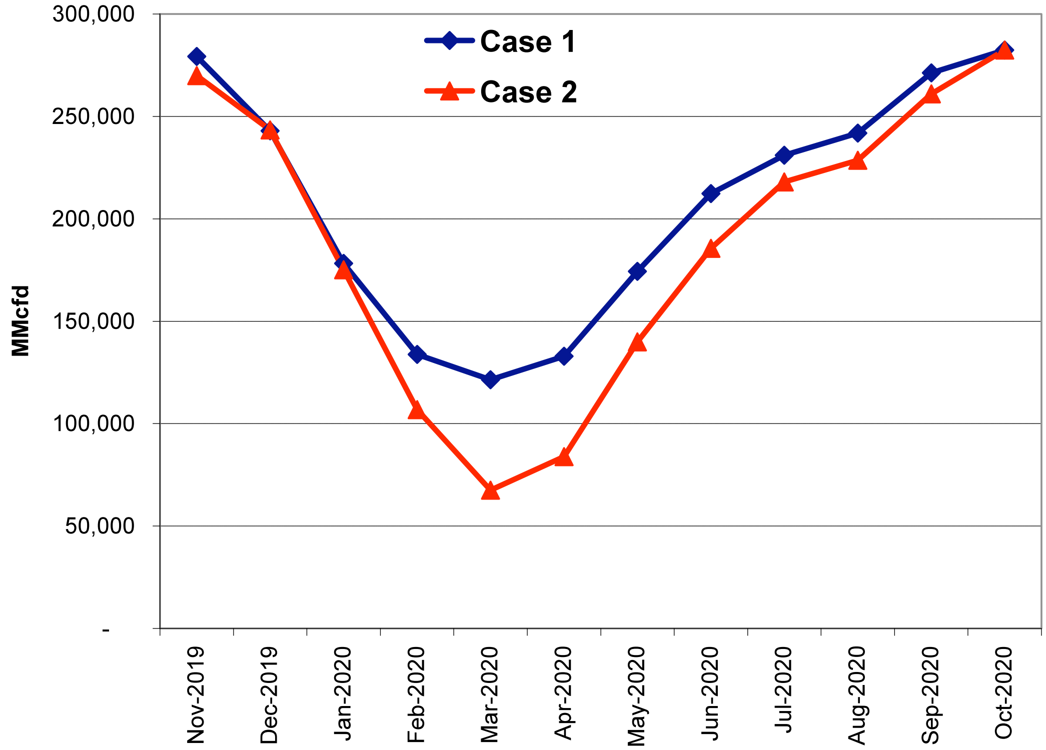


Figure 25: California Storage End-of-Month Working Gas Levels, Case 2 vs. Case 1
Source: ICF International

5.2.2. Peak Analysis

January 2020 peak day consumption in Case 2 totals about 9.3 BCF, or about 1.2 BCF greater than in Case 1 (Figure 26). About 60 percent (700 MMCF) of the increase is in the power sector. Residential and commercial demands are up about 500 MMCF over Case 1, accounting for the remaining 40 percent of the total increase. There is no significant change in industrial gas demand between the two cases.

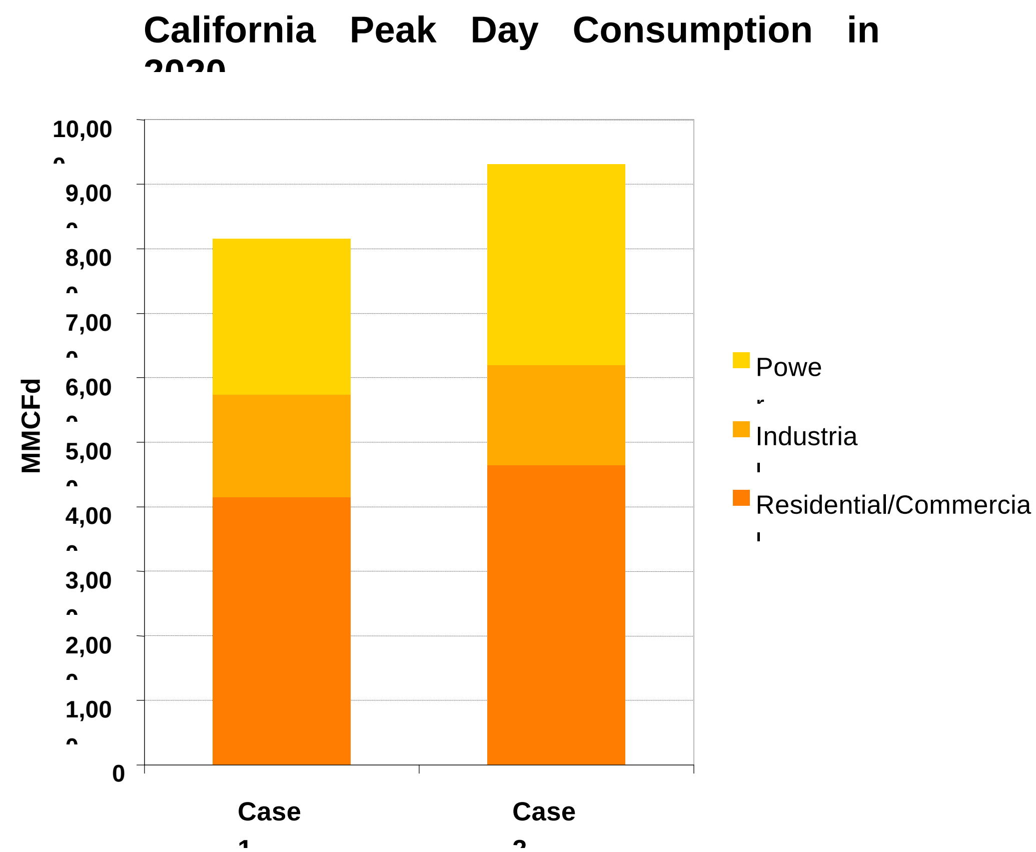
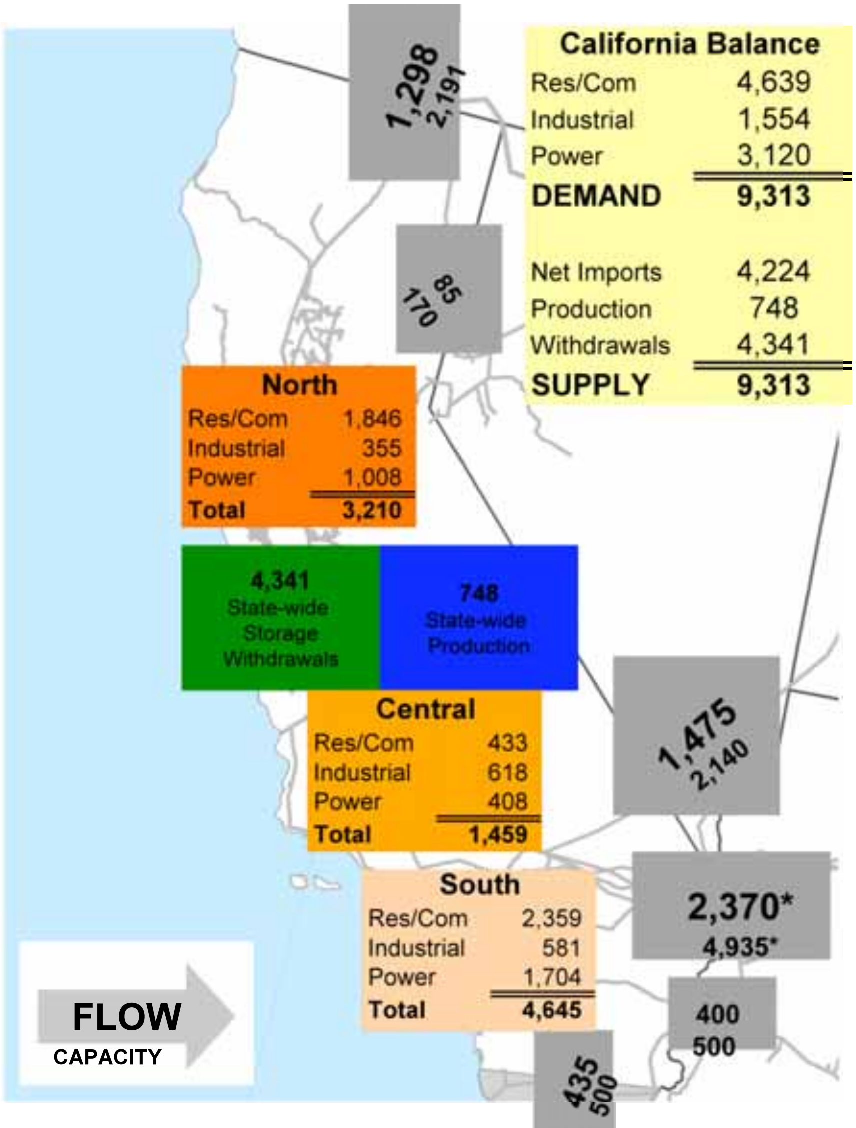


Figure 26: California January 2020 Peak Day Gas Consumption, Case 2 vs. Case 1
Source: ICF International

The adverse conditions in Case 2 increase January peak day natural gas consumption throughout California, with the most significant increase occurring in Southern California (Figure 27). In Southern California gas consumption is up by nearly 570 MMCF, compared to Case 1. Of this increase, roughly 63 percent is in the power sector. Northern California's peak day consumption is about 480 MMCF greater than in Case 1, and Central California is about 110 MMCF greater than in Case 1.

Most of the increase in peak day demand Case 2 is met by increased storage withdrawals. In total, peak day withdrawals are up 750 MMCF, compared to Case 1. Pipeline imports into California are up a by 410 MMCF. Most of the increase in pipeline imports occurs along the El Paso system into Southern California. Despite the additional 1.2 BCF of supply necessary to fulfill demand on a January peak day under adverse temperature and hydroelectric conditions, both pipeline flows and storage field withdrawals are well within their infrastructure capabilities.



* Total of El Paso, Transwestern, and Southern Trails

Figure 27: January 2020 Peak Day Balance (MMCFd), Case 2

Source: ICF International

Compared to Case 1, peak day demand in Southern and Central California in Case 2 is about 680 MMCF higher (Figure 28). Power sector demand in the area increases the most, by about 420 MMCF. The residential and commercial sectors account for the remainder of the increase; they are up by about 290 MMCF, compared to Case 1.

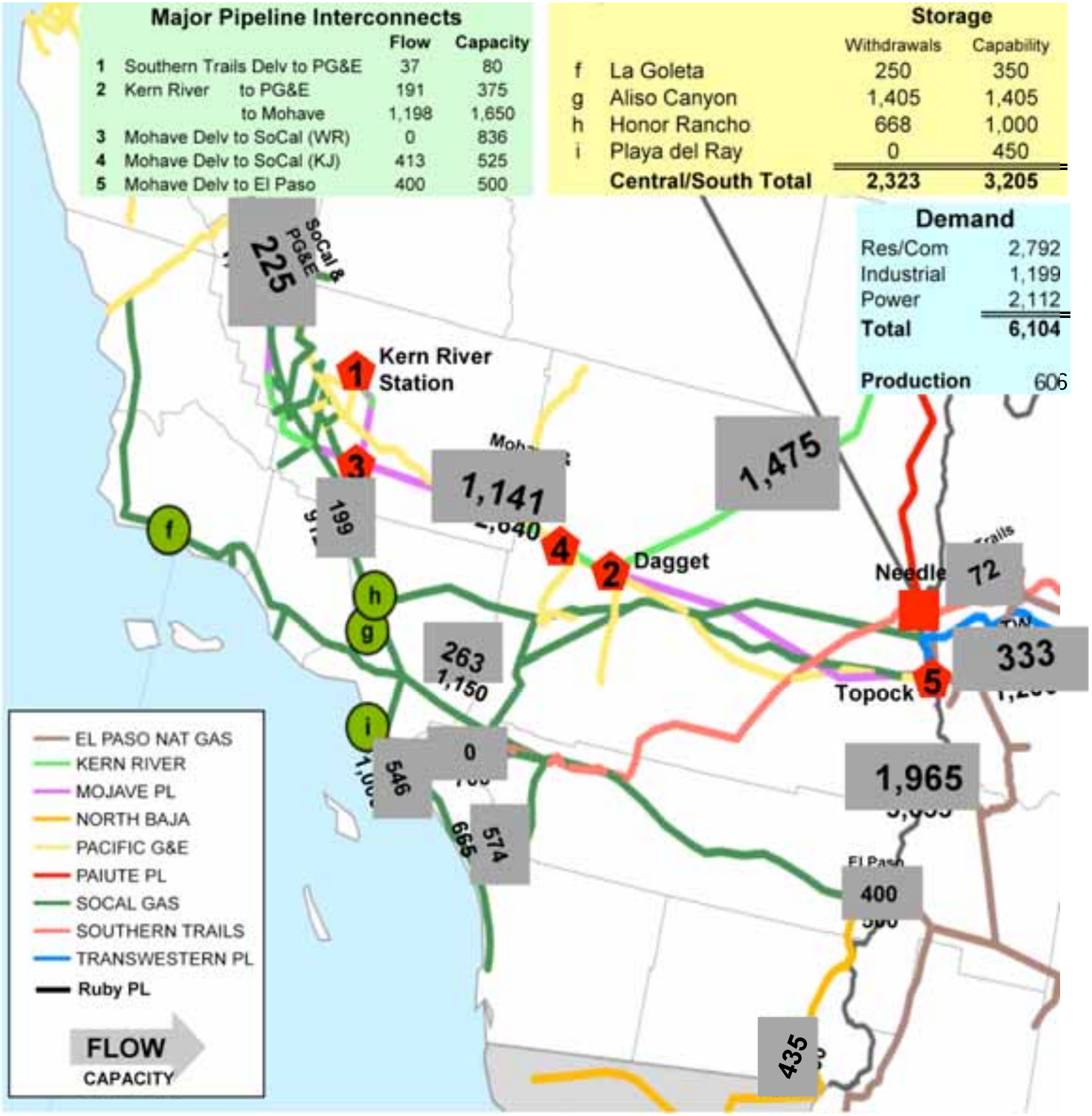


Figure 28: January 2020 Peak day Flows in Southern/Central California (MMCFd), Case 2

Source: ICF International

Area pipeline imports are up by around 380 MMCF, while storage withdrawals are up by close to 270 MMCF. Most of pipelines and storage fields within the area are well within system constraints, although load factors on pipelines into San Diego County are near 90 percent. Under adverse conditions in both the winter and summer months (when power generation gas use peaks), pipelines into San Diego could become constrained due to the lack of storage availability and limited pipeline options into the region.

Southern/Central California's average daily demand in January in Case 2 are up by around 330 MMCF compared to Case 1 (Figure 29). Average monthly pipeline flows are higher than in Case 1, but average daily storage withdrawals are similar.

Compared to the peak day of demand for Case 2, the average daily demand in January is almost 1.2 BCF lower. All of the additional peak day demand is met by additional storage withdrawals, which are about 1.3 BCF higher on the peak day.

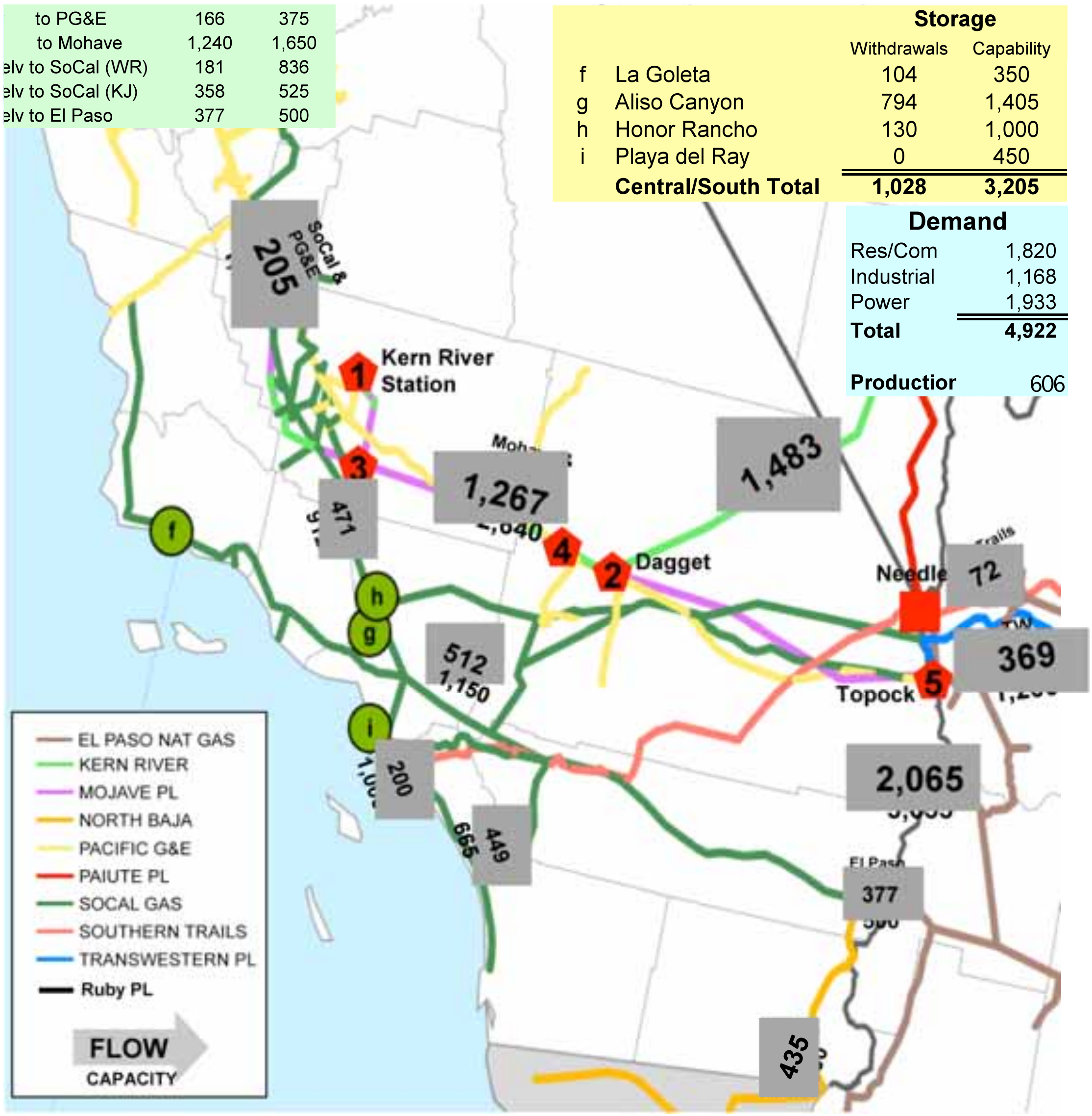


Figure 29: January 2020 Average Flows in Southern/Central California (MMCFd), Case 2

Source: ICF International

Northern California peak day gas consumption in January is about 480 MMCF higher in Case 2 when compared to Case 1 (Figure 30). This increased demand is split between the residential/commercial and power sectors. The increased demand in Northern California is met by additional storage withdrawals. This result may not what would happen in reality accurately since the RIAMS model uses inter-temporal optimization methods in order to solve for each scenario. In reality, it is likely that pipeline flows into Northern California given this scenario would increase somewhat and storage withdrawals would not cover the entire increase in demand. However, even if storage withdrawals were lower, there is still ample pipeline capacity into the region to meet the January peak day demand.

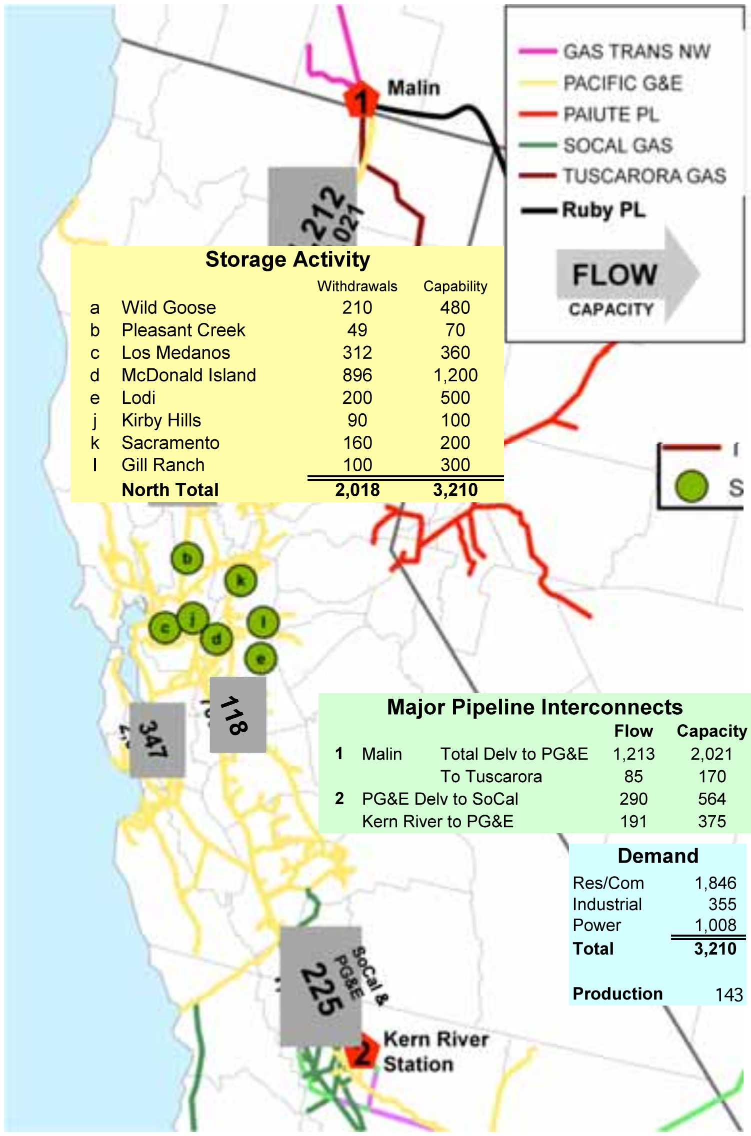


Figure 30: January 2020 Peak Day Flows in Northern California (MMCFd), Case 2

Source: ICF International

Compared to Case 1, average daily January gas consumption in Northern California is up by over 210 MMCF in Case 2 (Figure 31). The power sector accounts for all of the additional demand compared to Case 1. All of the incremental demand is met by increased natural gas storage withdrawals in the region.

In Northern California, demand on the average day in January is about 760 MMCF lower than the peak day. Unlike in Southern California, the majority of additional peak day demand in Northern California occurs in the residential and commercial sectors. Compared to the average day, peak day power sector demand is about 100 MMCF higher, while residential/commercial demand is up by almost 650 MMCF. All the additional peak day demand is met by additional storage withdrawals.

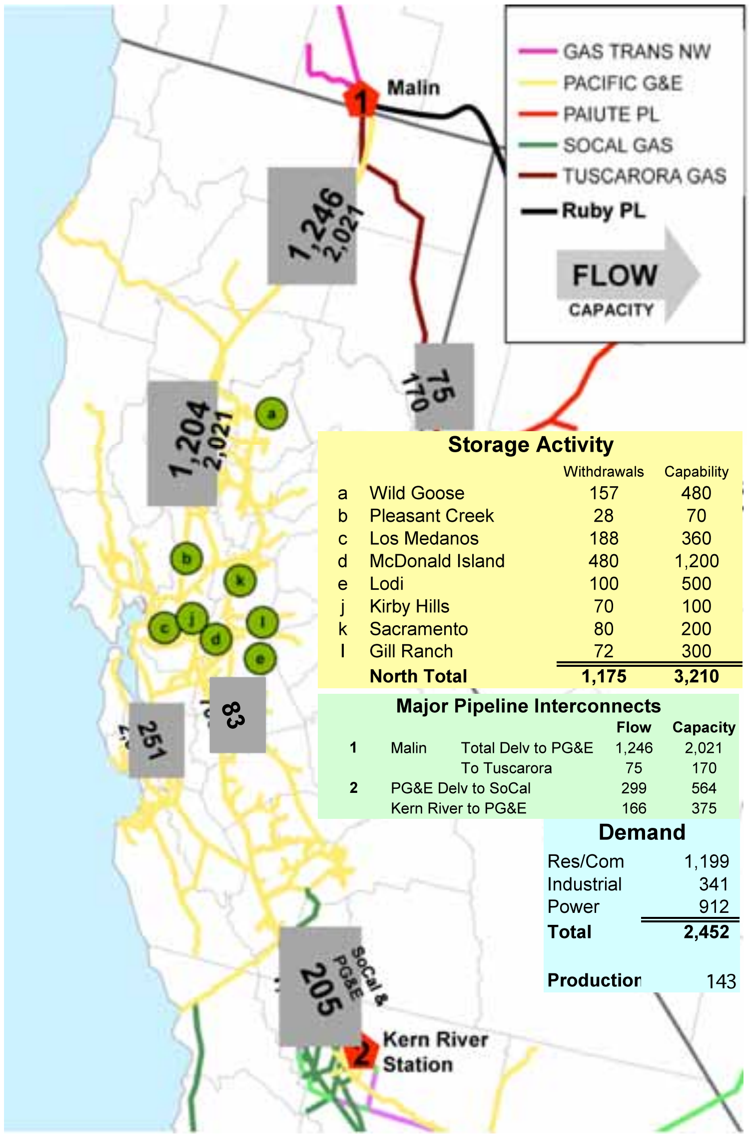


Figure 31: January 2020 Average Flows in Northern California (MMCFd), Case 2

Source: ICF International

5.3. Case 3: 33 Percent RPS Reference Scenario With Reduced Renewable Generation and Adverse Weather

5.3.1. Case Results Overview

In addition to the adverse weather and hydroelectric generation conditions, Case 3 tests the ability of California's natural gas system to cope with a reduction in renewable generation in 2020, based on the 33 Percent RPS Reference scenario. Case 3 reduces California's annual renewable generation in 2020 by 11 TWh, or about 11 percent. As a result of the reduction in renewable generation, California's annual gas consumption in 2020 is 0.2 BCFd greater than in Case 2 (Table 6).

Table 6: California's Natural Gas Balance, Case 3 vs. Case 2

BCFd	2020 Case	*Delta Case*
Consumption	**6.2**	***0.2***
Residential	1.2	*(0.00*
Commercial	0.6	*(0.00*
Industrial	1.4	*(0.00*
Power Generation	2.7	*0.2*
Other	0.1	*0.0*
Pipeline Exports	**0.0**	***(0.00***
To Northern Nevada	0.0	*0.0*
To Mexico	0.0	*(0.00*
Production	**0.8**	***0.0***
Pipeline Imports	**5.5**	***0.2***
Via Southern Nevada (Kern River)	1.7	*(0.03*
Via Arizona (El Paso, Transwestern)	2.2	*0.1*
Via Malin	1.4	*0.0*
Via Mexico (Costa Azul LNG)	0.0	*0.0*
Storage Net Injections / (Withdrawals)	**-**	-
Balancing Item	**0.0**	***0.0***

Source: ICF International

As would be expected, all of the increase in demand for natural gas is in the power generation sector, as gas is used to fill the gap in renewable generation for the year. To fulfill the increased demand, imports along the El Paso / Transwestern corridor and at the Malin interchange are up by about 160 MMCFd and 60 MMCFd, respectively. Imports along the Kern River pipeline are down relative to Case 2 by about 30 MMCFd.

As shown in Figure 32, compared to Case 2, average monthly gas consumption in the reduced renewable generation scenario is up by between 100 and 300 MMCFd throughout 2020. In the winter peak month of January average gas consumption is up by about 200 MMCFd, equal to about the same as the annual average increase. In August, the summer peak demand month, gas demand is up only by about 100 MMCFd, mainly due to the reductions in wind and solar generation.

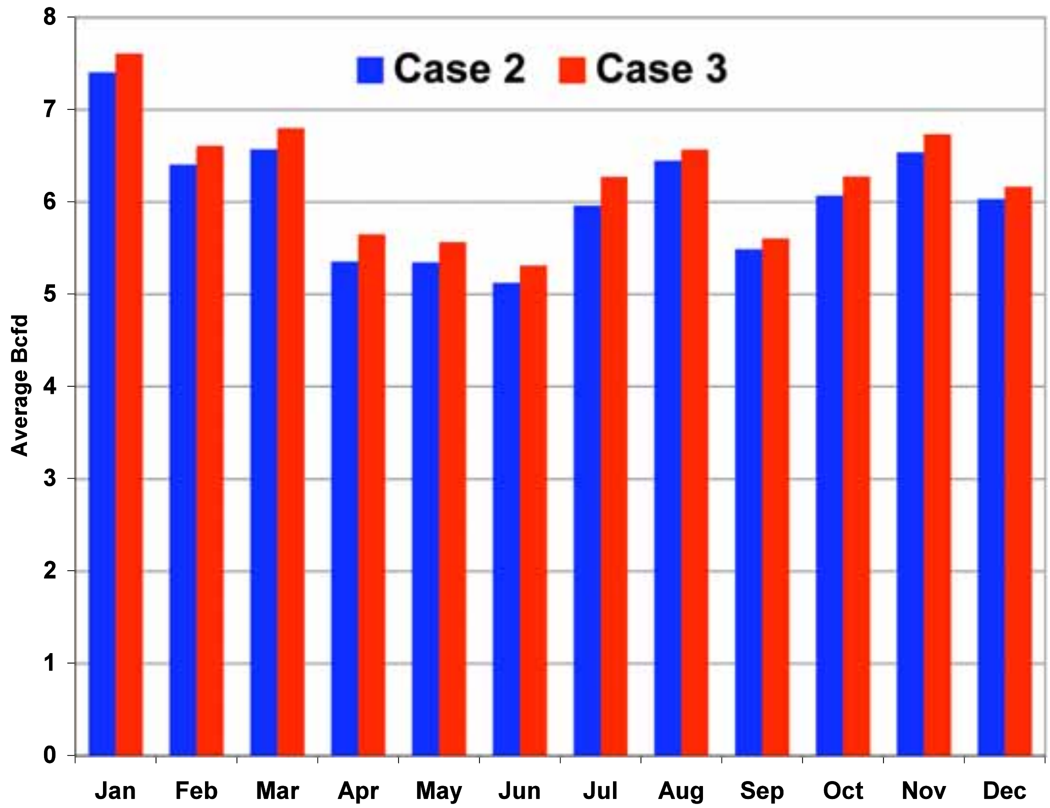


Figure 32: California Monthly Gas Consumption in 2020, Case 3 vs. Case 2
Source: ICF International

Despite the necessity of additional gas supplies for the state of California due to the reduction in renewable generation, gas storage withdrawals within the state are very close to those observed in Case 2 (Figure 32).

Through January, storage withdrawals in both cases are almost identical. By the end of the withdrawal season in March, 2020, the difference in withdrawals between the two cases is still barely noticeable. In the reduced renewable generation scenario, only an additional 1.4 BCF is withdrawn from storage by March compared to Case 2, with a little more than 66 BCF of gas left in storage by the end of the season.

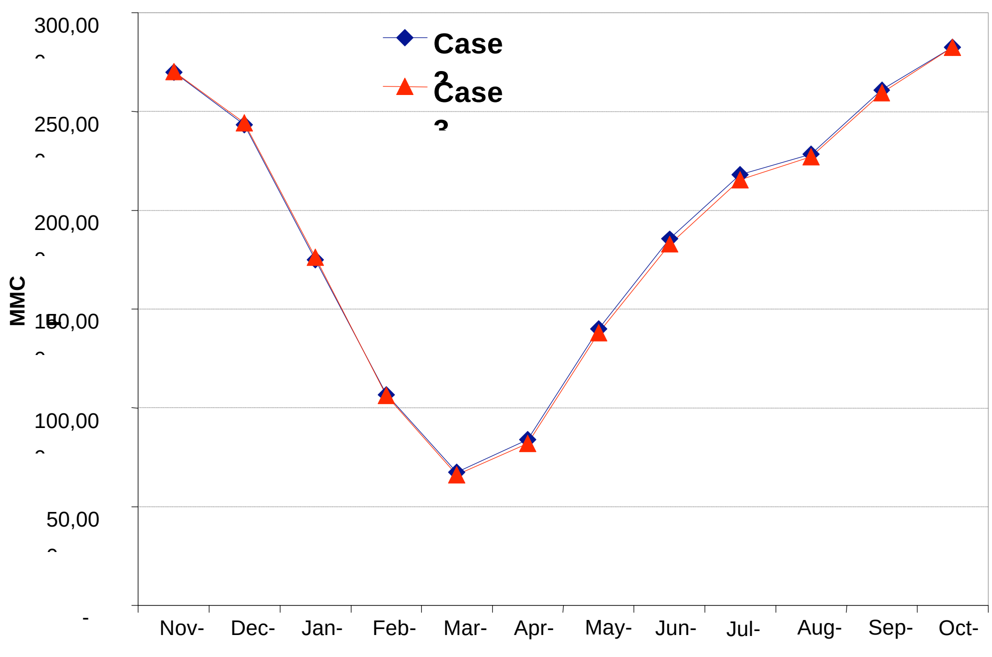


Figure 33: California Storage End-of-Month Working Gas Levels, Case 3 vs. Case 2

Source: ICF International

5.3.2. Peak Analysis

Peak day gas consumption in January in Case 3 is about 460 MMCF higher than in Case 2 (Figure 34). As Case 3 assumes the same weather conditions as Case 2, all of the additional gas demand occurs in the power generation sector.

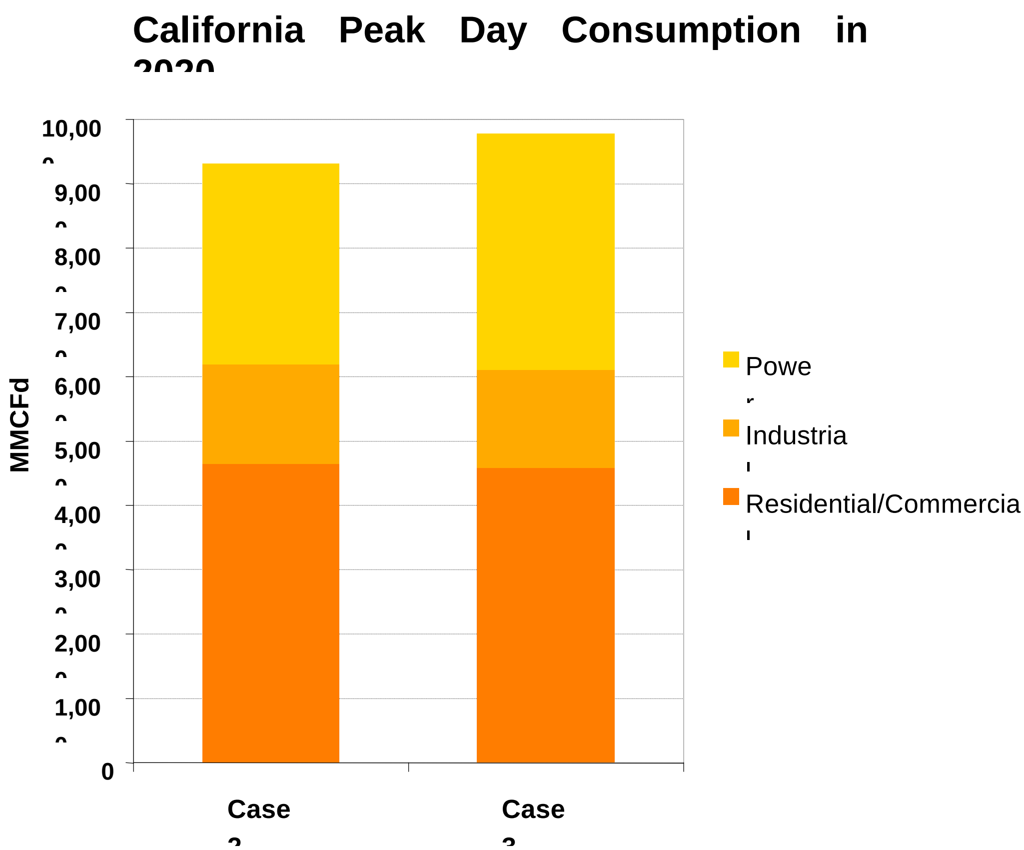


Figure 34: California January 2020 Peak Day Gas Consumption, Case 3 vs. Case 2
Source: ICF International

Due to the reduced renewable generation on the peak day, gas consumption is up in the power sector throughout California, with Southern California requiring the most additional gas supply, with nearly an additional 270 MMCF of gas needed in the region. In Northern California, an additional 220 MMCF of gas is required to fill the additional power demand, while only about 60 MMCF is needed in Central California (Figure 35). In both Central and Northern California industrial and residential and commercial demand is relatively flat, but in Southern California demand in both sectors is down slightly.

The majority of this increased demand is filled by increased pipeline imports. In total, an additional 330 MMCF of gas is imported to California on the peak day in Case 3 over Case 2. Most of the additional gas is imported along the El Paso line in Southern California. Additional storage withdrawals account for about an additional 150 MMCF of supply. Most of the increase in storage withdrawals is concentrated at the Aliso Canyon and Honor Rancho fields near Las Angeles. In this scenario, storage withdrawals on the peak day in January are at or near capacity at many fields within the state.

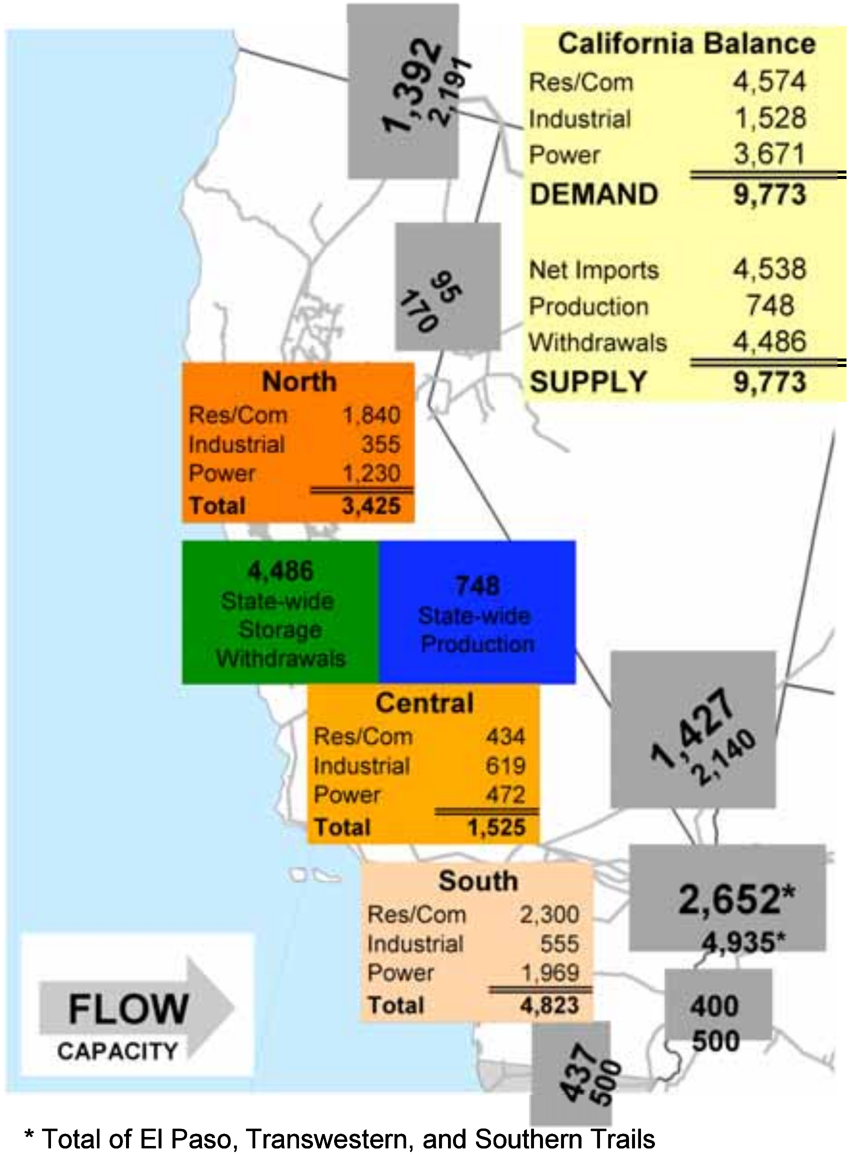


Figure 35: January 2020 Peak Day Balance (MMCFd), Case 3

Source: ICF International

In Southern and Central California, the reduced generation available from renewable power sources causes a demand increase for natural gas of about 250 MMCF compared to Case 2 (Figure 36). This increase in demand is met primarily by an increase in pipeline imports along the El Paso corridor, which are about 280 MMCF higher than in Case 2 at around 2,250 MMCF. Storage withdrawals in the region are about the same as in Case 2, only up by about 10 MMCF.

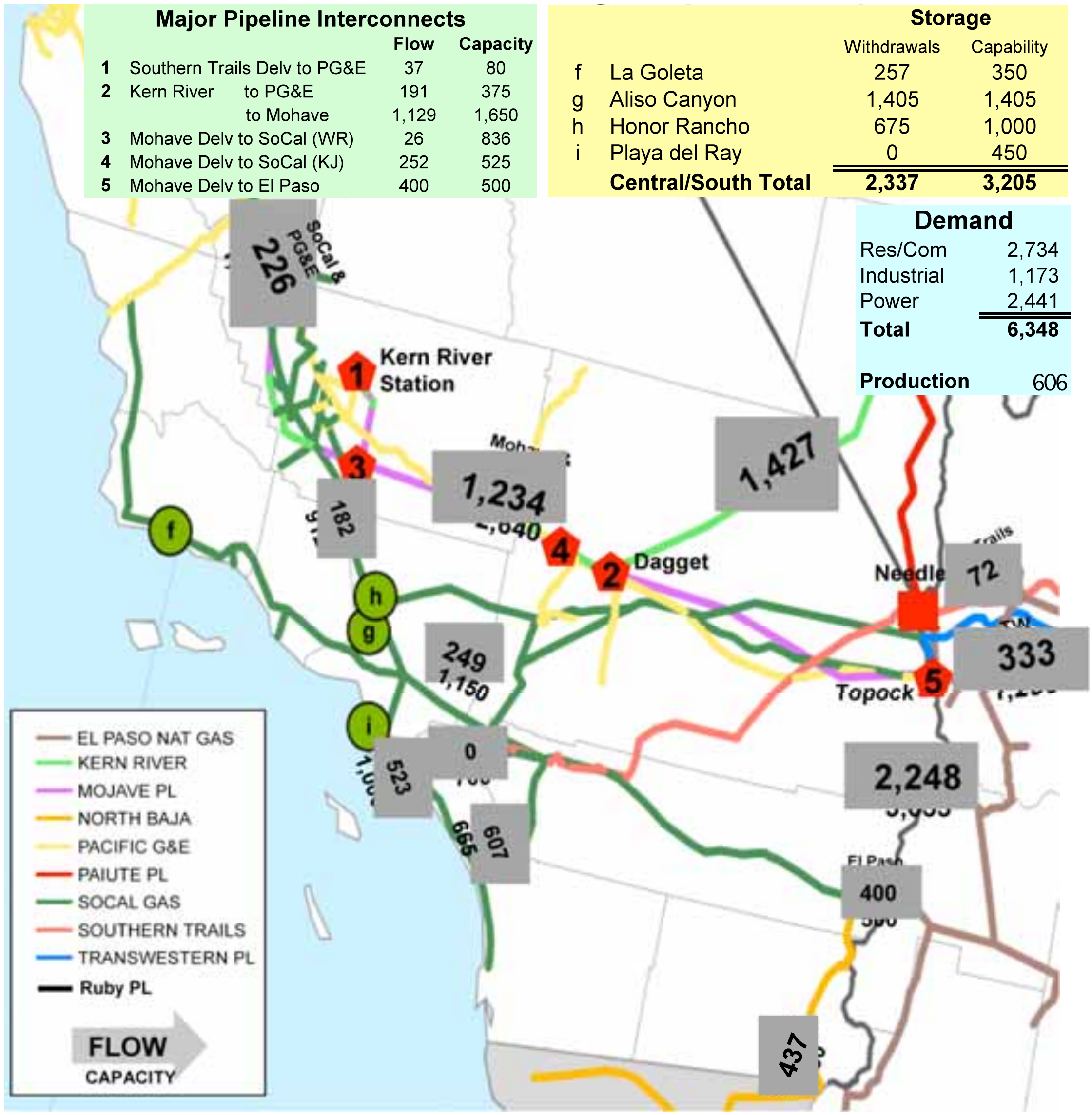


Figure 36: January Peak Day Flows in Southern/Central California (MMCFd), Case 3
Source: ICF International

For the majority of Southern and Central California, pipeline and storage capacity is adequate to meet the increased demand levels brought on by the lower renewable generation levels in Case 3. As in Case 2, the one area where potential problems could arise is in the San Diego area since, unlike the Las Angeles Basin, San Diego has no storage fields in its direct vicinity. In this scenario, load factors on pipeline serving San Diego are over 90 percent, almost at the constraining point. In a peak power generation demand month like August, the city would most likely be constrained if renewable generation were to be as low as it is in Case 3.

Average daily gas demand in Southern and Central California in January is only about 90 MMCF higher than in Case 2 (Figure 37). Almost all of this additional demand is met by increased imports along El Paso's system, which is up by about 150 MMCF at around 2.2 BCF.

Imports along Kern River's line are about 70 MMCF lower, and intrastate flows from Central California to Northern California are up by about 25 MMCF.

Compared to the average January day, peak day gas demand is about 1.3 BCF higher in Case 3, with residential/commercial demand about 920 MMCF higher and power sector demand about 420 MMCF higher. Industrial sector demand is roughly the same on a peak day and an average day. All of the additional gas required to fill peak day demand is met by additional storage withdrawals.

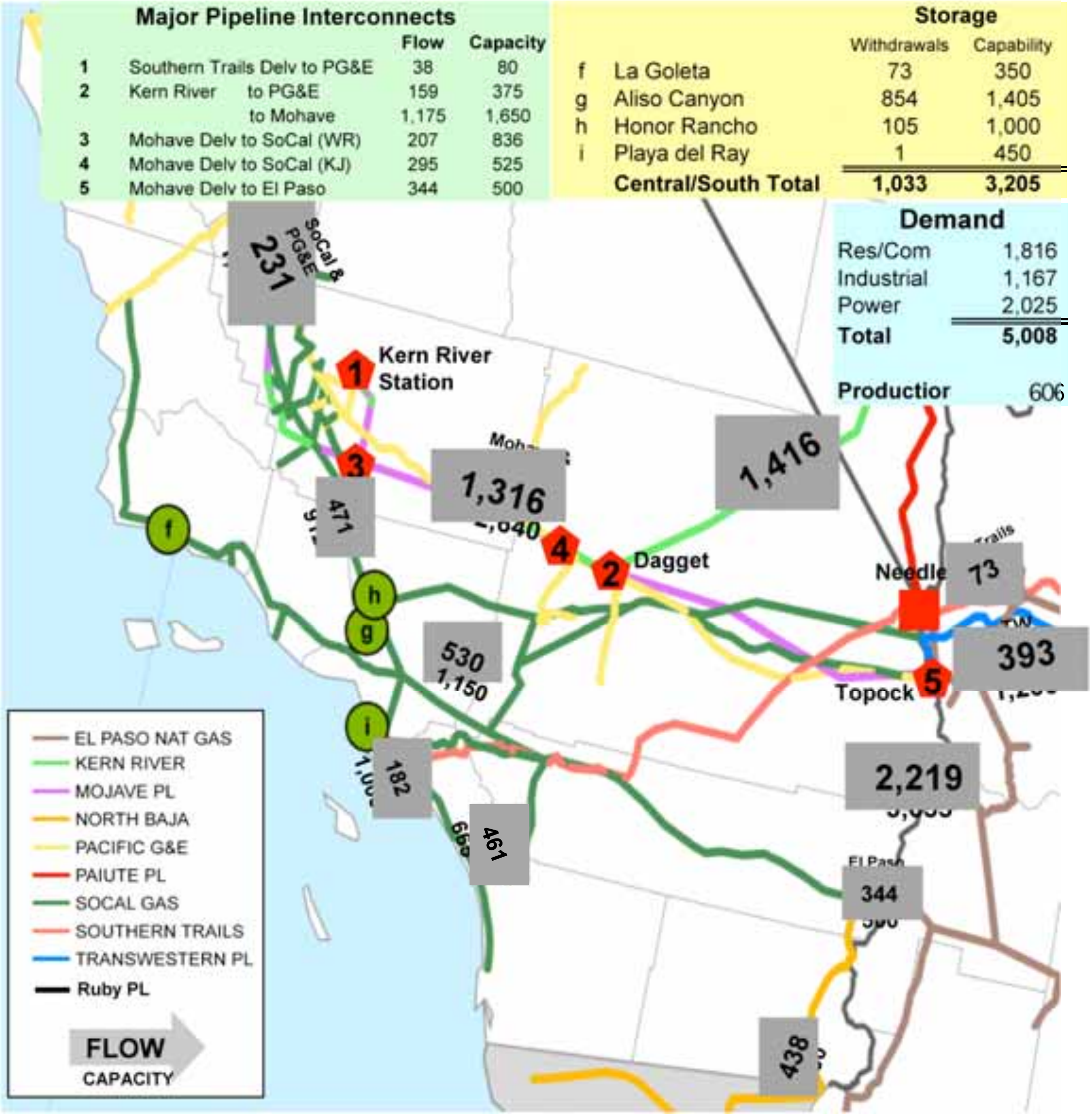


Figure 37: January 2020 Average Flows in Southern/Central California (MMCFd), Case 3

Source: ICF International

In Northern California, the reduced renewable generation in Case 3 creates an additional 220 MMCF of gas for the power sector on the peak demand day in January 2020 (Figure 38). About 90 MMCF of the increase is met by increased imports at Malin, and 130 MMCF is met by additional storage withdrawals within the region. Four of the area's eight storage fields – Pleasant Creek, Los Medanos, Kirby Hills, and Sacramento – are withdrawing at their full capability on the peak day. This reflects a tendency of the RIAMS to maximize withdrawals from particular fields due to their proximity to load centers. However, even if withdrawals at these four fields were lower, there are ample remaining pipeline capacity and storage withdrawal capability at other fields to meet peak day demand.

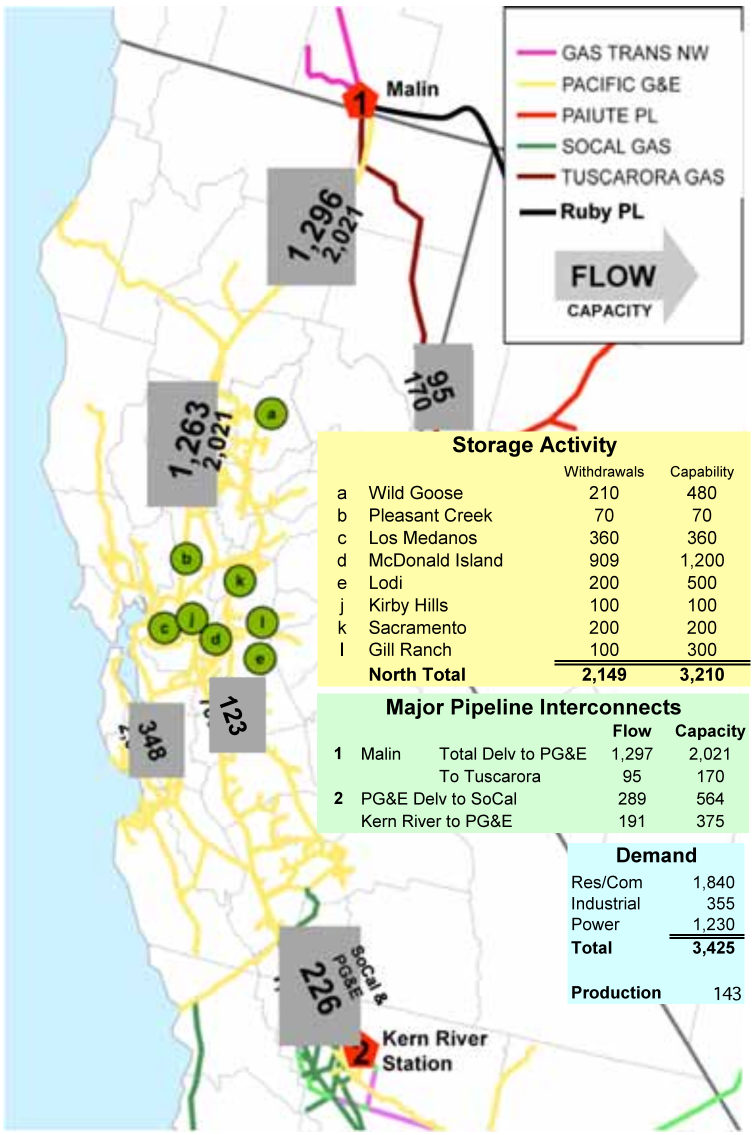


Figure 38: January Peak Day Flows in Northern California (MMCFd), Case 3

Source: ICF International

Despite the increased need for gas-fired generation in Case 3 over Case 2, Northern California average daily demand in January is only about 50 MMCF greater in Case 3 (Figure 39). All of the additional demand is concentrated in the power sector. The incremental demand increase is met by a combination of additional imports at Malin and storage withdrawals within the region.

January average daily demand in Northern California is about 700 MMCF less than on the peak day. Residential/commercial gas demand is about 650 MMCF higher on a peak day, while power sector demand is about 40 MMCF higher. All of the supply needed to fill peak day demand compared to average daily demand in the region comes from additional storage withdrawals.

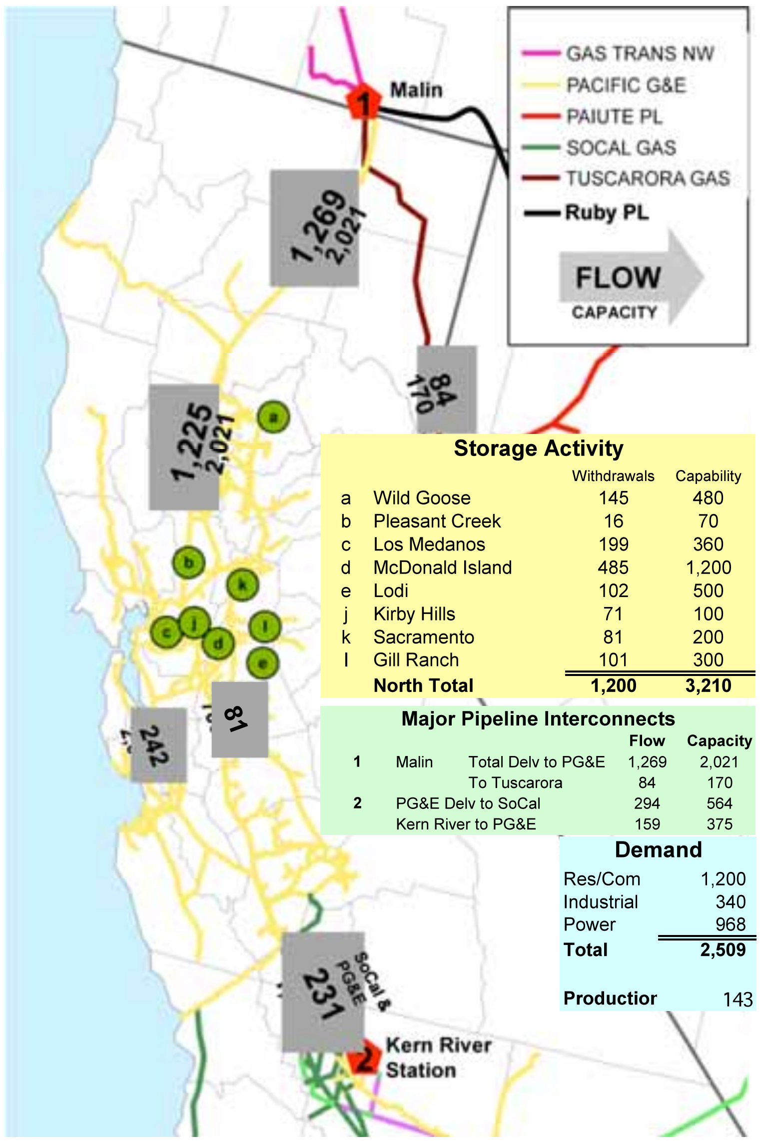


Figure 39: January 2020 Average Flows in Northern California (MMCFd), Case 3
Source: ICF International

5.4. Case 4: 33 Percent RPS High Wind Scenario With Reduced Renewable Generation and Adverse Weather

5.4.1. Case Results Overview

Case 4 assumes the same adverse weather and hydroelectric generation conditions as Case 2 and a reduction in renewable generation in 2020 similar to Case 3, but the seasonal pattern of renewable generation is based on the High Wind RPS scenario. In Case 4, annual renewable generation is reduced by 12 TWh in 2020. Among all of the outage cases, Case 4 has the greatest reduction in renewable generation, but only by about 1 TWh compared to Case 3.

The reduced renewable generation leads to an increase in average annual power generation gas demand of about 220 MMCFd, just slightly higher than the increase observed in Case 3 (Table 7). And, similar to Case 3, the gas imports along the El Paso/Transwestern corridor and at Malin act as the primary sources of the additional supply needed.

Table 7: California's Natural Gas Balance, Case 4 vs. Case 2

Bcfd	**2020** Case 4	*Delta vs Case 2*
Consumption	**6.2**	***0.2***
Residential	1.2	*(0.00)*
Commercial	0.6	*(0.00)*
Industrial	1.4	*(0.00)*
Power Generation	2.7	*0.2*
Other	0.13	*0.00*
Pipeline Exports	**0.0**	***(0.00)***
To Northern Nevada	0.0	*0.0*
To Mexico	0.05	*(0.00)*
Production	**0.85**	***0.00***
Pipeline Imports	**5.5**	***0.2***
Via Southern Nevada (Kern River)	1.7	*(0.03)*
Via Arizona (El Paso, Transwestern)	2.2	*0.1*
Via Malin	1.4	*0.0*
Via Mexico (Costa Azul LNG)	0.04	*0.01*
Storage Net Injections / (Withdrawals)	**-**	-
Balancing Item	**0.04**	***0.00***

Source: ICF International

Compared to Case 2, the monthly average gas consumption in 2020 for Case 4 is up between 110 MMCFd and 370 MMCFd (Figure 39). In January, average consumption is up by about 220 MMCFd, which is about equal to the average annual increase. Consumption in the peak summer month of August is up by about 120 MMCFd.

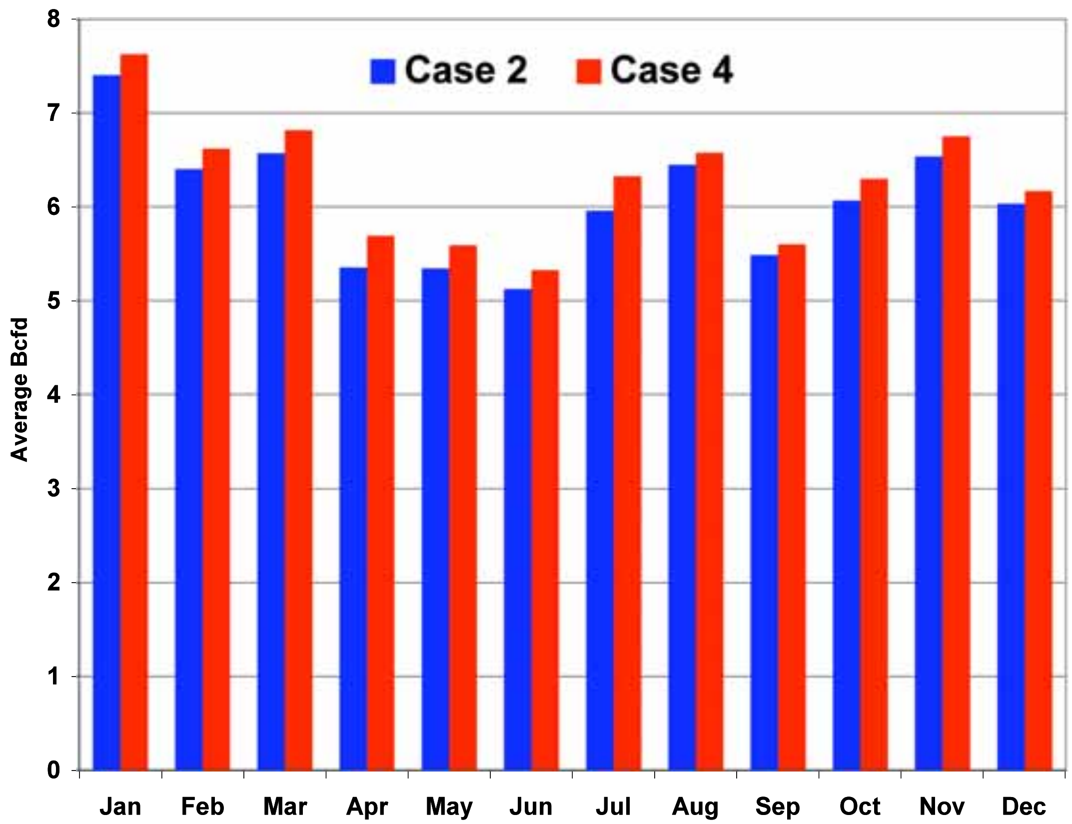


Figure 40: California Monthly Gas Consumption in 2020, Case 4 vs. Case 2
Source: ICF International

Monthly storage withdrawals within California in Case 4 are very similar those observed in Case 2 (Figure 41). By the end of the withdrawal season in March 2020, the amount of gas left in storage in Case 4 is about 1.4 BCF lower than the level in Case 2, an incremental decrease of about 2 percent.

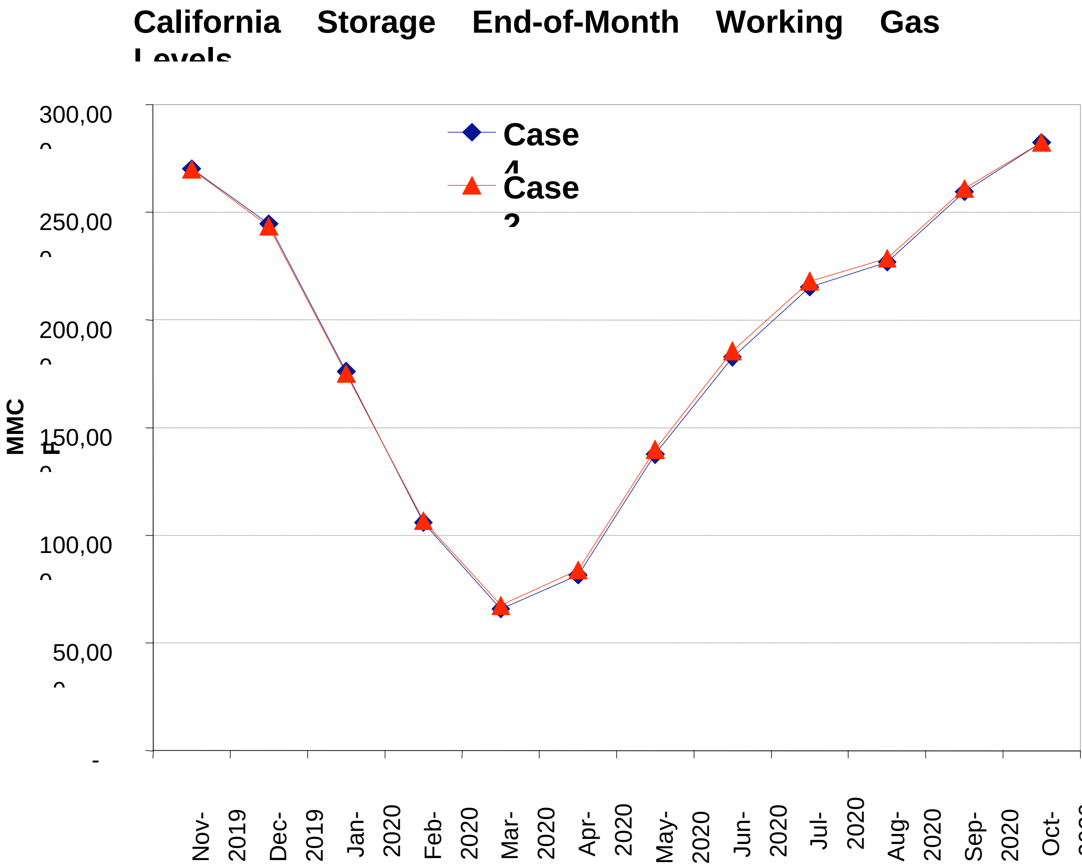


Figure 41: California Storage End-of-Month Working Gas Levels, Case 5 vs. Case 2
Source: ICF International

5.4.2. Peak Analysis

In January 2020, peak day consumption in Case 4 is 9.9 BCF, or about 570 MMCF greater than in Case 2 (Figure 42). Compared to Case 2, all of the additional peak day demand is in this scenario is in power sector.

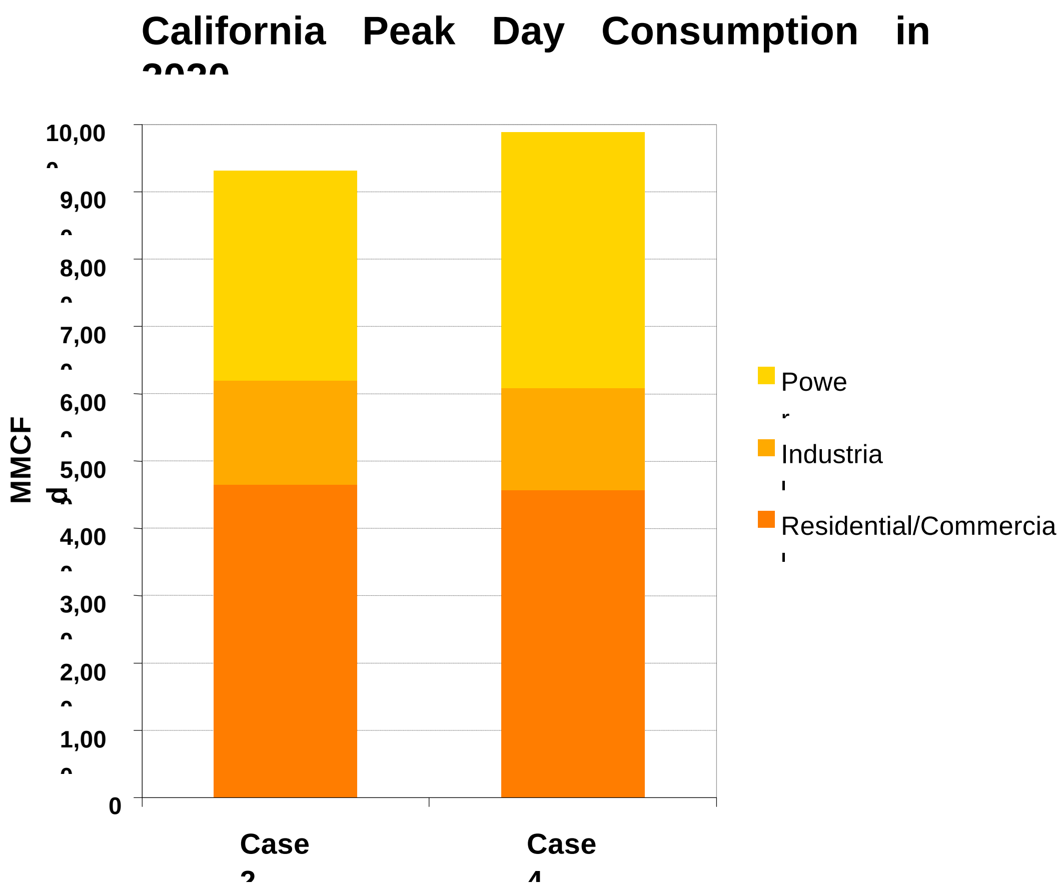
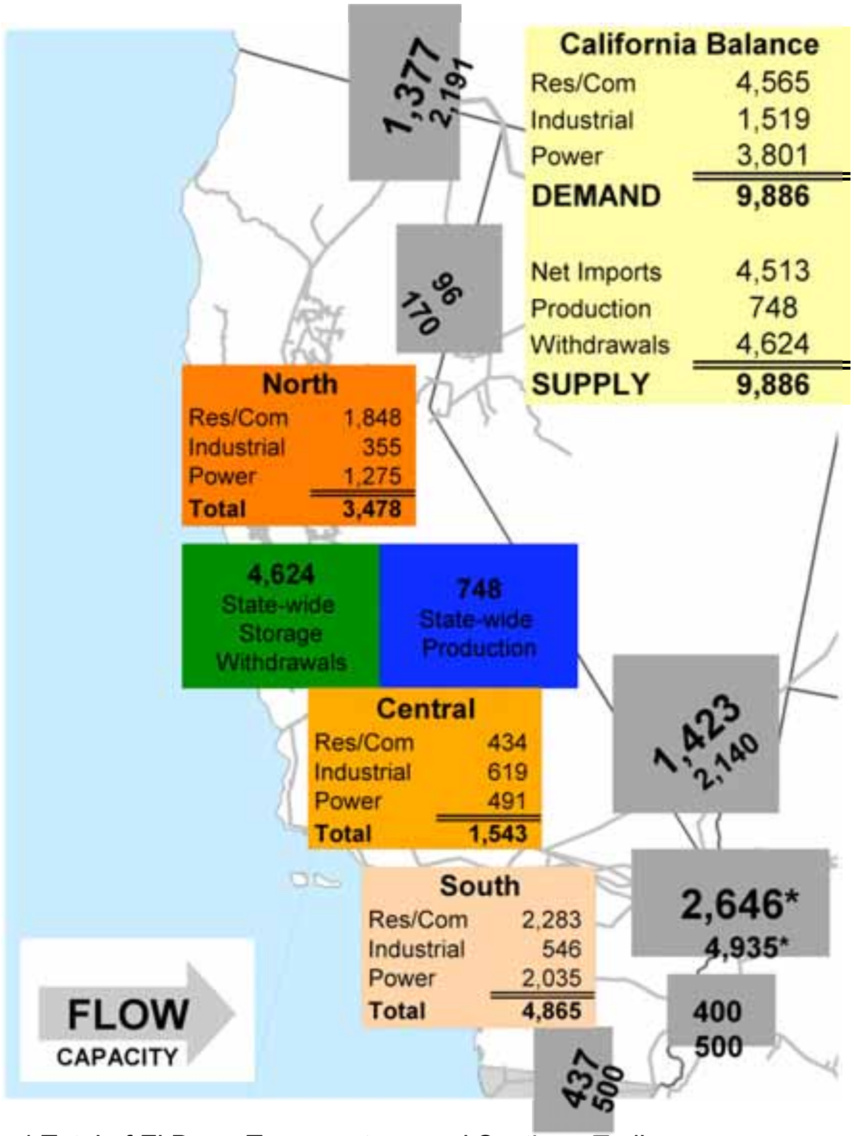


Figure 42: California January 2020 Peak Day Gas Consumption, Case 4 vs. Case 2
Source: ICF International

Southern California shows a slightly larger increase in power generation demand than other areas in the state (Figure 43). In Southern California, peak day power generation demand is up by about 330 MMCF, while demand in Northern California is up by about 270 MMCF and only by about 80 MMCF in Central California. The additional demand is met by a combination of additional pipeline imports and storage withdrawals. Compared to Case 2, pipeline imports are up by 300 MMCF, while an additional 280 MMCF is withdrawn from storage on a peak day. The majority of the additional pipeline imports enter the state via the El Paso / Transwestern corridor. Similar to in Case 3, storage withdrawals are at, or near, capacity at many fields within California.



* Total of El Paso, Transwestern, and Southern Trails

Figure 43: January 2020 Peak Day Balance (MMCFd), Case 4

Source: ICF International

The reduction in renewable generation causes a demand increase of about 300 MMCF in southern and central California compared to Case 2 (Figure 44). Most of this increase in demand is met by increased imports of gas along El Paso's system (280 MMCF). Additional storage withdrawals account for the remaining supply needed. For the most part, pipeline and storage capacity in the region is adequate to meet demand. Similar to Case 3, load factors on the January peak day along pipelines serving San Diego County are over 90 percent. This is an indication that during both winter and summer peak gas demand periods it is likely that pipelines into San Diego would be constrained.

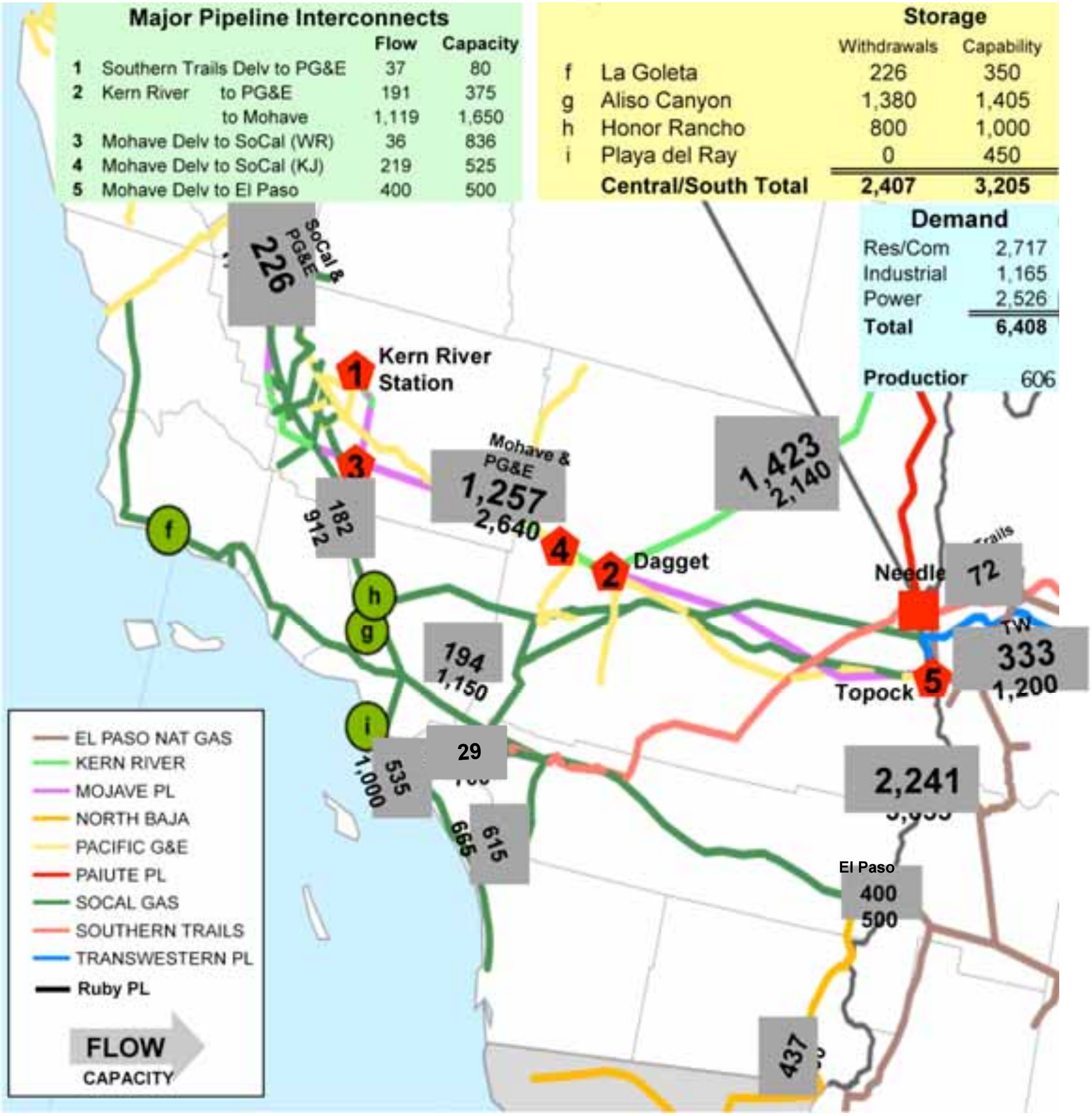


Figure 44: January 2020 Peak Day Flows in Southern/Central California (MMCFd), Case 4

Source: ICF International

The January daily average demand in Central/Southern California increases by 80 MMCF, compared to Case 2 (Figure 45). Pipeline imports on the El Paso system meet most the incremental demand increase on the average day in Case 4.

Compared to an average day in January 2020, demand on a peak day is about 1.4 BCF higher. Residential/commercial demand is about 900 MMCF higher on the peak day, while power sector demand is about 500 MMCFd higher. Compared to the average day, all of the incremental demand on the peak day comes from additional storage withdrawals.

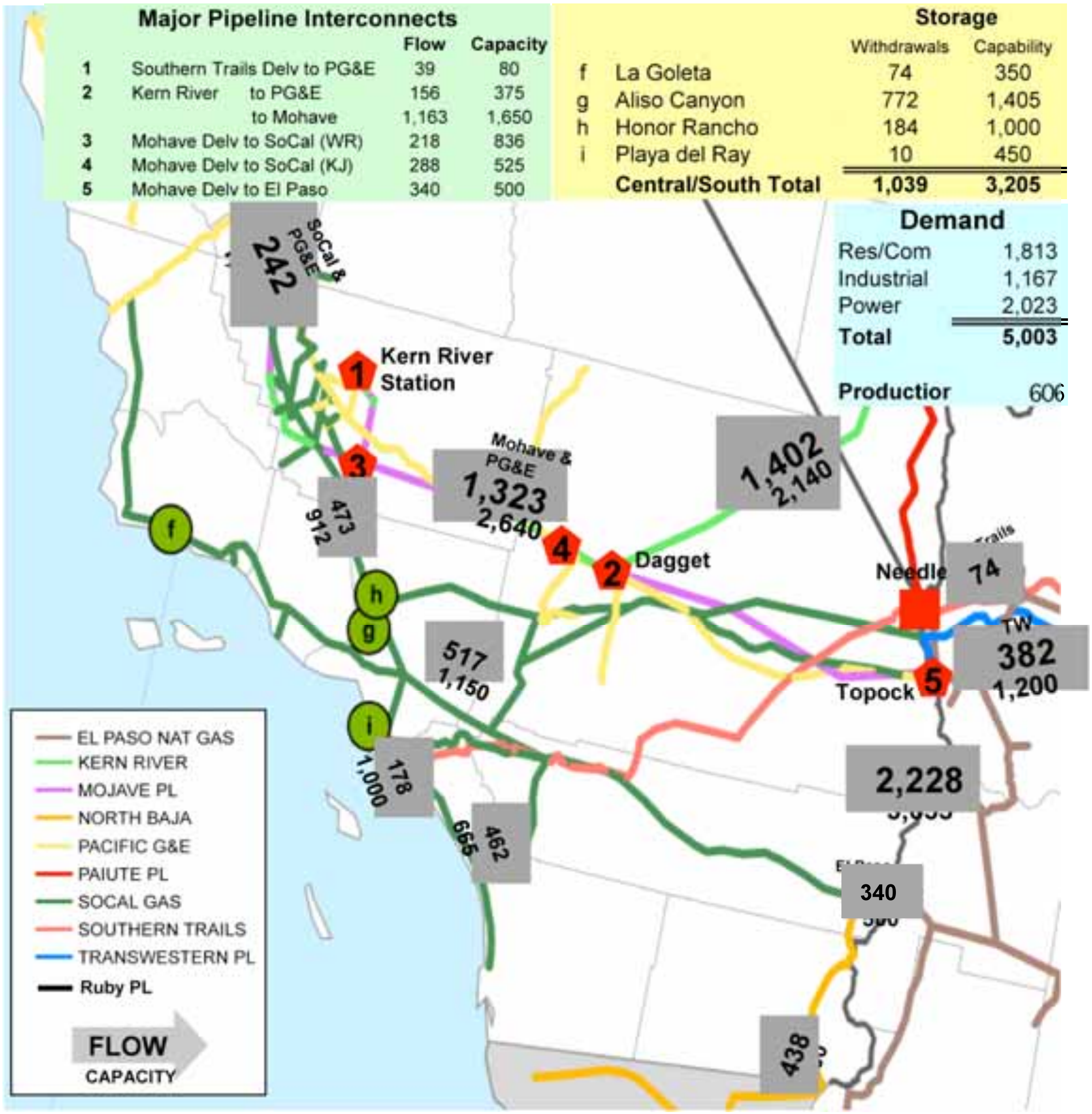


Figure 45: January 2020 Average Flows in Southern/Central California (MMCFd), Case 4

Source: ICF International

Compared to Case 2, January peak day demand in Northern California is up by about 270 MMCF in Case 4 (Figure 46). Most of the incremental demand increase is met by increased storage withdrawals, with the remainder being met by increased imports at Malin. As in Case 3, four of the eight storage fields in the region are withdrawing at their full capability. Even if withdrawals at these fields were lower, there is more than enough unused pipeline capacity and storage withdrawal capability to adequately meet the case's demand levels.

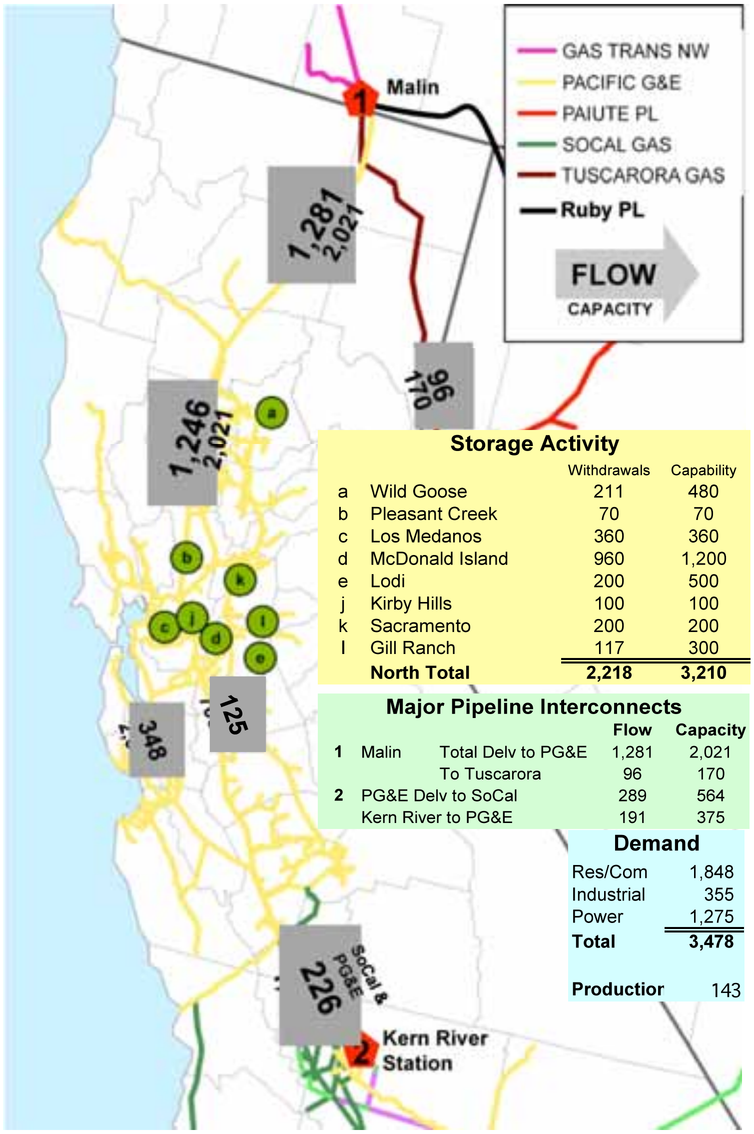


Figure 46: January 2020 Peak Day Flows in Northern California (MMCFd), Case 4
Source: ICF International

January average daily demand in the Northern California is about 60 MMCF higher than in Case 2 (Figure 47). The additional demand is met by slight increases in both pipeline imports at Malin and storage withdrawals.

Compared to the January average day demand in Case 4, the peak demand day is about 1,000 MMCF higher. About 650 MMCFd of the increase is in residential/commercial demand, while the remainder of the increase is in the power sector. Compared to the average January day, storage withdrawals are about 1,000 MMCF higher to meet the demand increase.

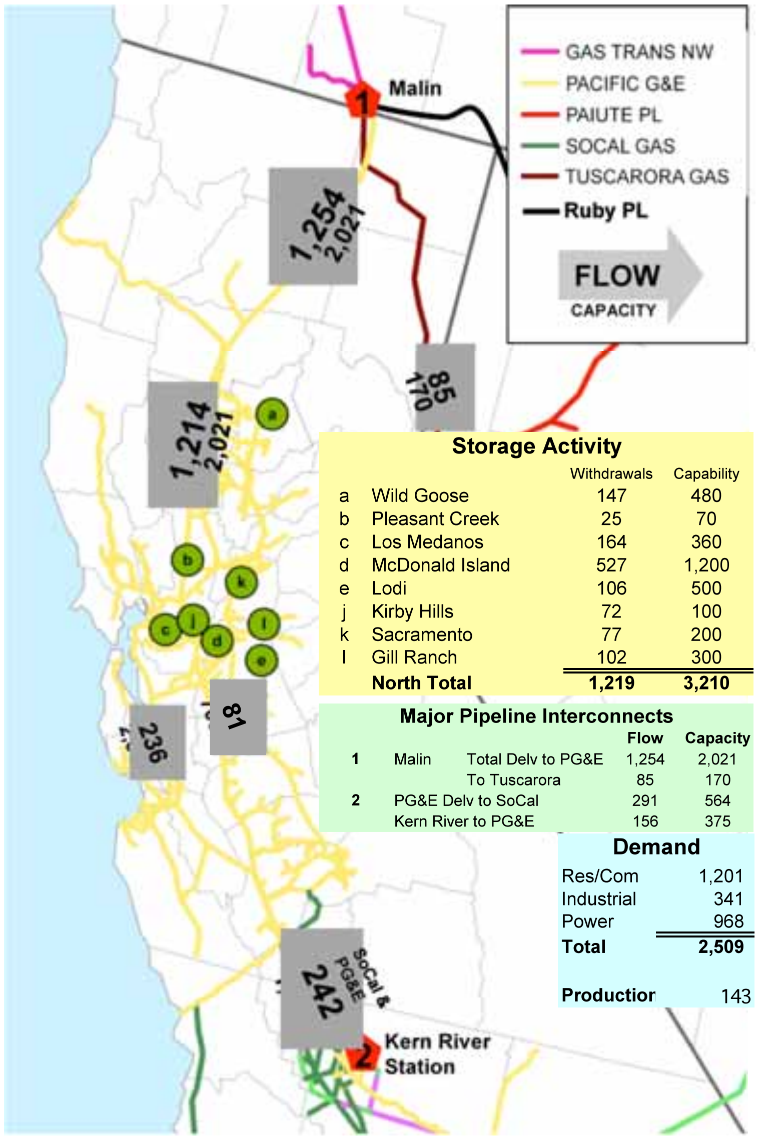


Figure 47: January 2020 Average Flows in Northern California (MMCFd), Case 4
Source: ICF International

5.5. Case 5: 33 Percent RPS Solar Scenario With Reduced Renewable Generation and Adverse Weather

5.5.1. Case Results Overview

Case 5 reduces annual renewable generation in 2020 by about 10 TWh, or roughly 10 percent, compared to the expected annual renewable generation. Of the three reduced renewable generation cases, this scenario has the smallest reduction in annual generation, though it only differs from Case 3 by about 0.2 TWh. The reductions in renewable generation lead to an average annual increase in power generation gas consumption of about 190 MMCFd (Table 8). As in Cases 3 and 4, this additional demand is met by increased imports of natural gas along the

El Paso / Transwestern corridor in Southern California and at the Malin interchange in northern California.

Table 8: California's Natural Gas Balance, Case 5 vs. Case 2

Bcf	2020 Case	Delta Case
Consumption	**6.2**	***0.1***
Residential	1.2	*(0.00*
Commercial	0.6	*(0.00*
Industrial	1.4	*(0.00*
Power Generation	2.7	*0.2*
Other	0.1	*0.0*
Pipeline Exports	**0.0**	***(0.00***
To Northern Nevada	0.0	*0.0*
To Mexico	0.0	*(0.00*
Production	**0.8**	***0.0***
Pipeline Imports	**5.5**	***0.1***
Via Southern Nevada (Kern River)	1.7	*(0.02*
Via Arizona (El Paso, Transwestern)	2.2	*0.1*
Via	1.4	*0.0*
Via Mexico (Costa Azul LNG)	0.0	*0.0*
Storage Net Injections / (Withdrawals)	**-**	*-*
Balancing Item	**0.0**	***0.0***

Source: ICF International

Compared to Case 2, average gas consumption in Case 5 is up by 100 MMCFd to 300 MMCFd each month in 2020 (Figure 48). This differential is very similar to Case 3 since the renewable generation levels are very similar in both cases. In January, the winter peak month, average consumption is up by about 210 MMCFd, which is about the same as the annual average increase. In the summer peak month of August, gas consumption is up by 110 MMCFd.

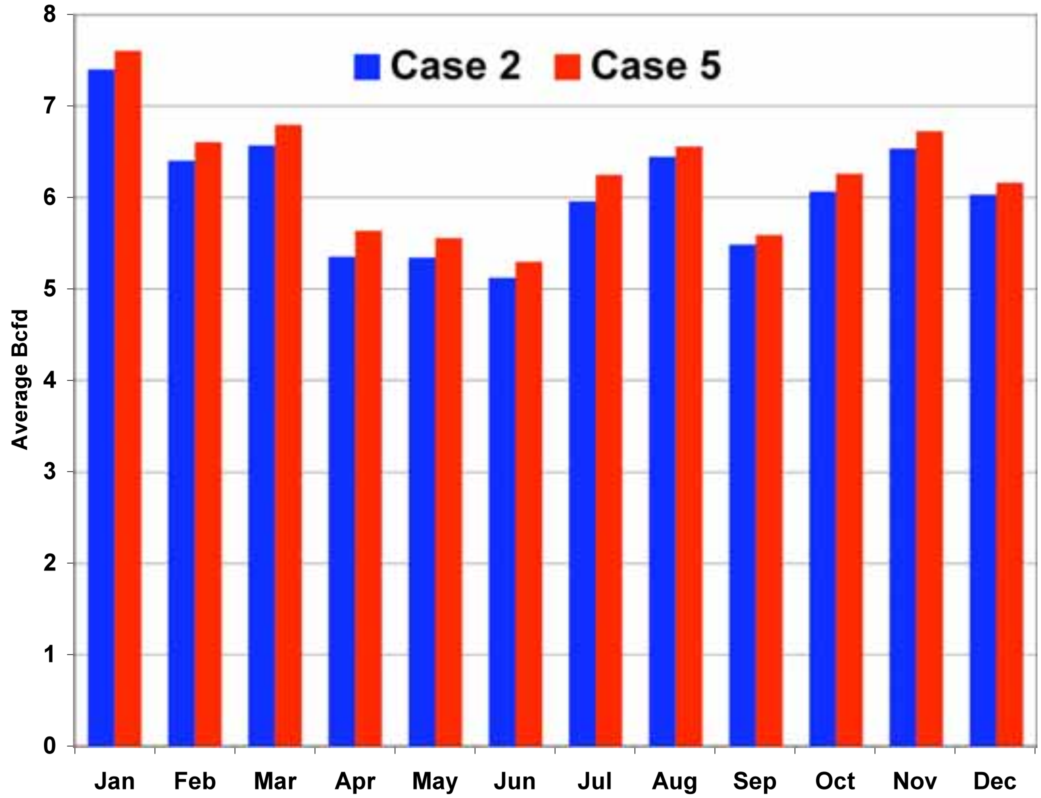


Figure 48: California Monthly Gas Consumption in 2020, Case 5 vs. Case 2
Source: ICF International

As in the other reduced renewable generation cases, monthly storage withdrawals in Case 5 are very similar to those in Case 2 (Figure 49). By the end of the storage withdrawal season in March 2020 the working gas level in Case 5 is only about 1.2 BCF lower than in Case 2.

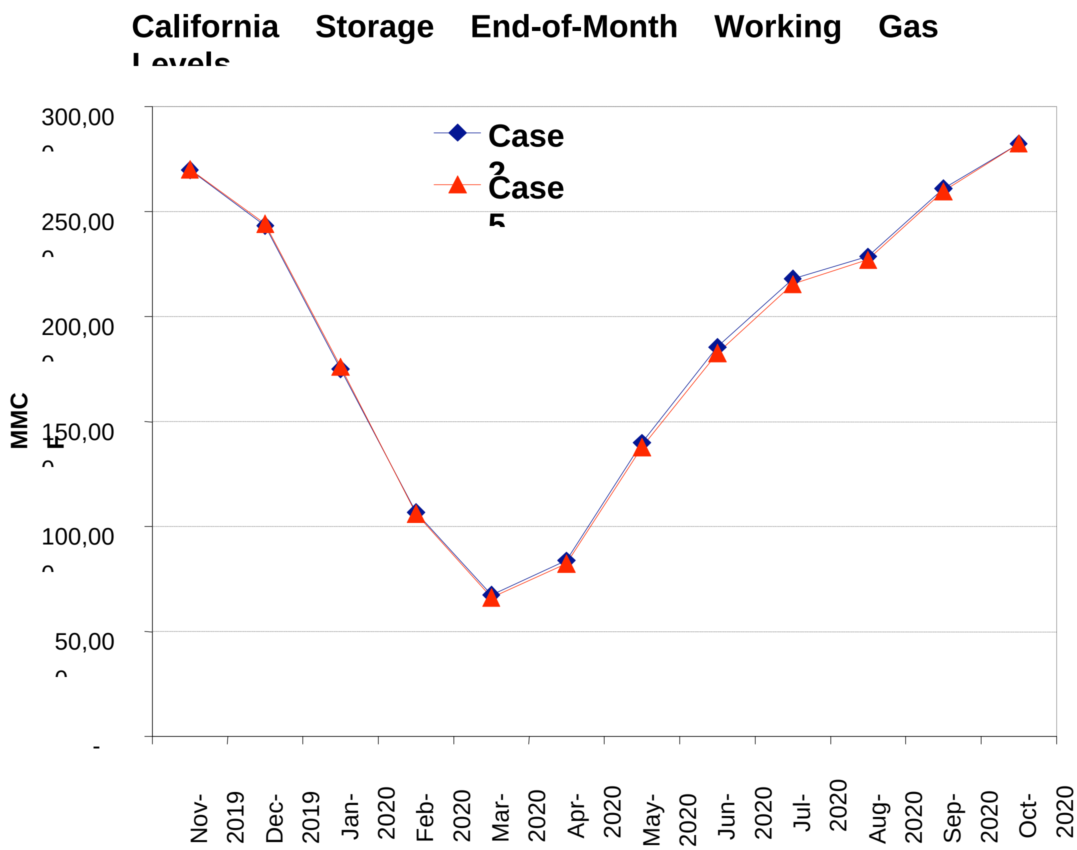


Figure 49: California Storage End-of-Month Working Gas Levels, Case 5 vs. Case 2
Source: ICF International

5.5.2. Peak Analysis

On the peak demand day in January 2020, total gas demand within California is about 9.8 BCF (Figure 50). This demand level is about 500 MMCF higher than that in Case 2 and all of the demand increase are in the power sector. Peak day demand in this scenario is about 70 MMCF less than in Case 4 (the High Wind RPS Reduced Generation case) and about 40 MMCF greater than in Case 3 (the Reference RPS Reduced Generation case).

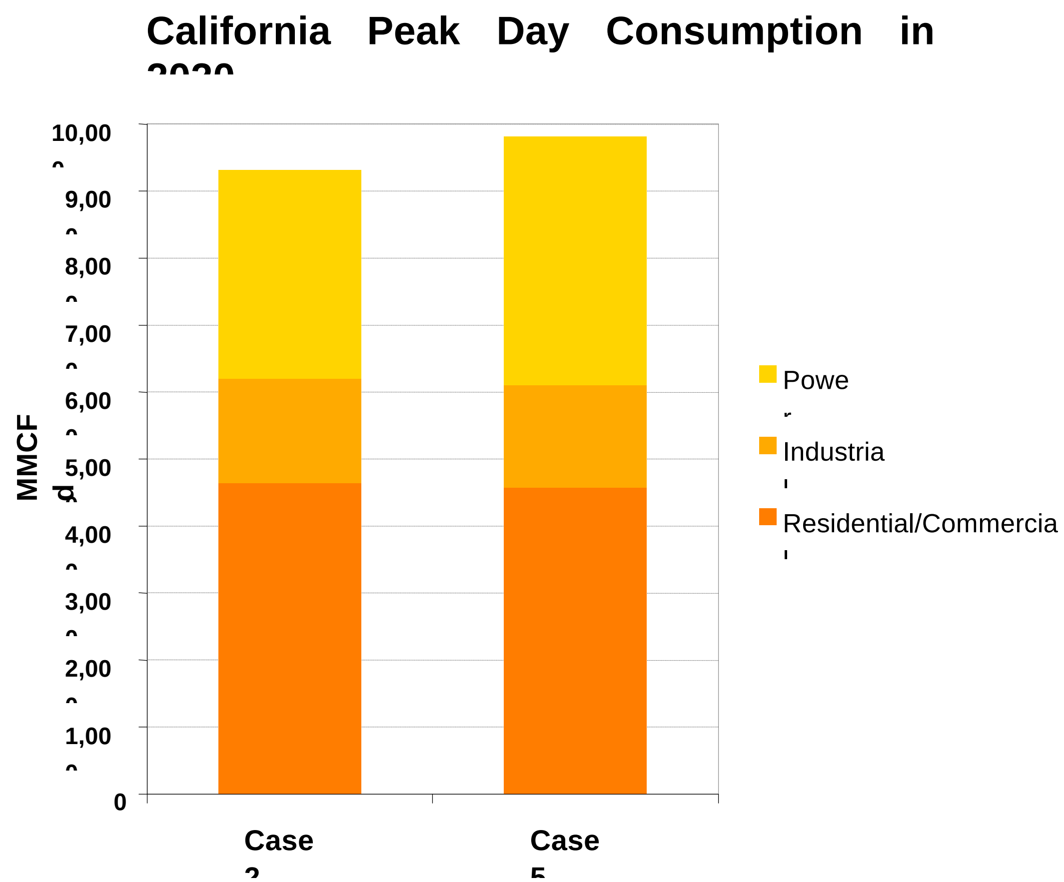
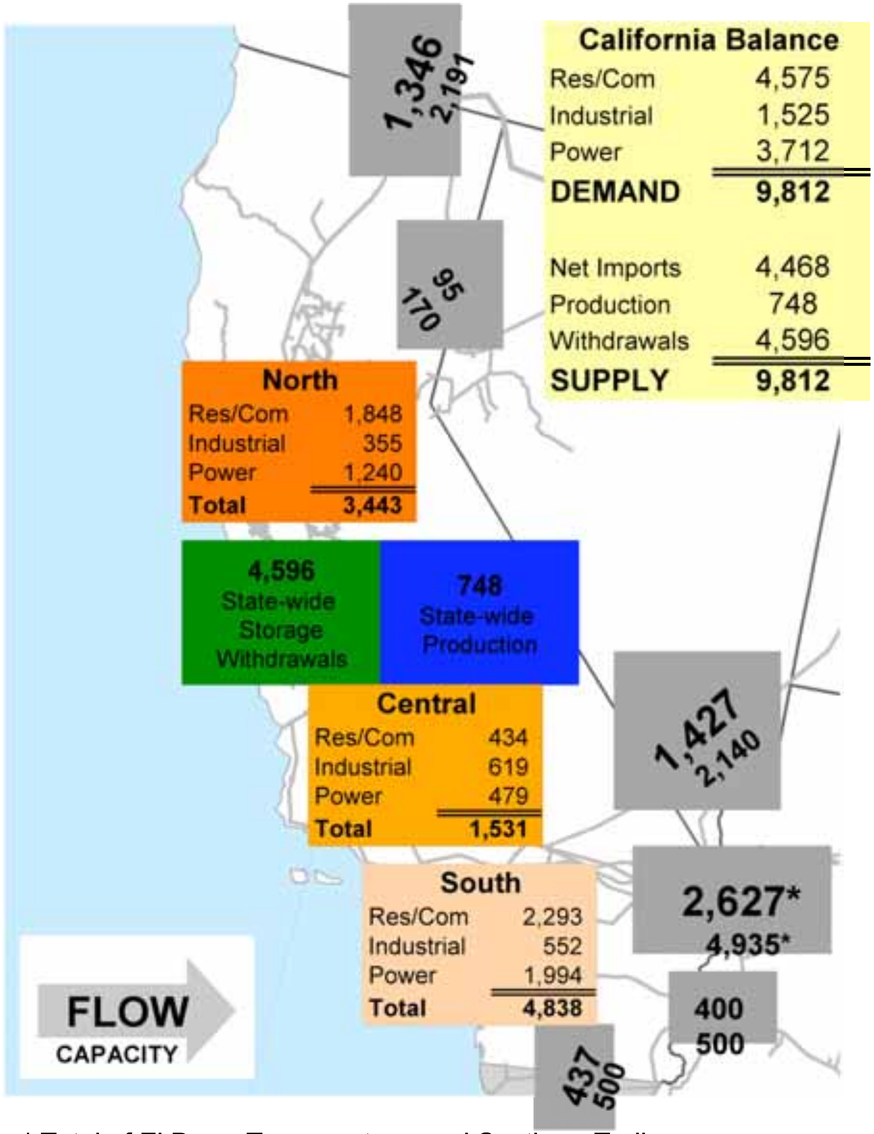


Figure 50: California January 2020 Peak Day Gas Consumption, Case 5 vs. Case 2
Source: ICF International

As in the other reduced renewable generation scenarios, January peak day gas consumption in the power sector is up throughout the state. The increase in Southern California is somewhat greater than that in Central or Northern California. Power generation demand in Southern California is up by 290 MMCF, while in Northern California demand is up by about 230 MMCF and in Central California demand is up by 70 MMCF (Figure 51). This increased demand is met by increased imports of natural gas into California and increased storage withdrawals. Most of the increase in pipeline imports is along the El Paso system in Southern California. Most of the increase in storage withdrawals is concentrated at the Aliso Canyon and Honor Rancho fields near Los Angeles. Throughout the state, storage withdrawals are at or near capacity at many fields.



* Total of El Paso, Transwestern, and Southern Trails

Figure 51: January 2020 Peak Day Balance (MMCFd), Case 5
Source: ICF International

The reduction in renewable generation in Case 5 causes a demand increase of about 270 MMCF in Southern and Central California compared to Case 2 (Figure 52). About 230 MMCF of the demand increase is met by increased natural gas pipeline imports on the El Paso system. The remainder of the demand increase is met with additional storage withdrawals within the area. As in the other reduced renewable generation scenarios, both pipeline and storage capacity appears to be adequate to meet peak day demand in the area. However, load factors along pipelines serving San Diego are over 90 percent. As in the other reduced renewable generation cases, pipelines serving the San Diego area may become constrained during peak gas demand periods in both the winter and summer months.

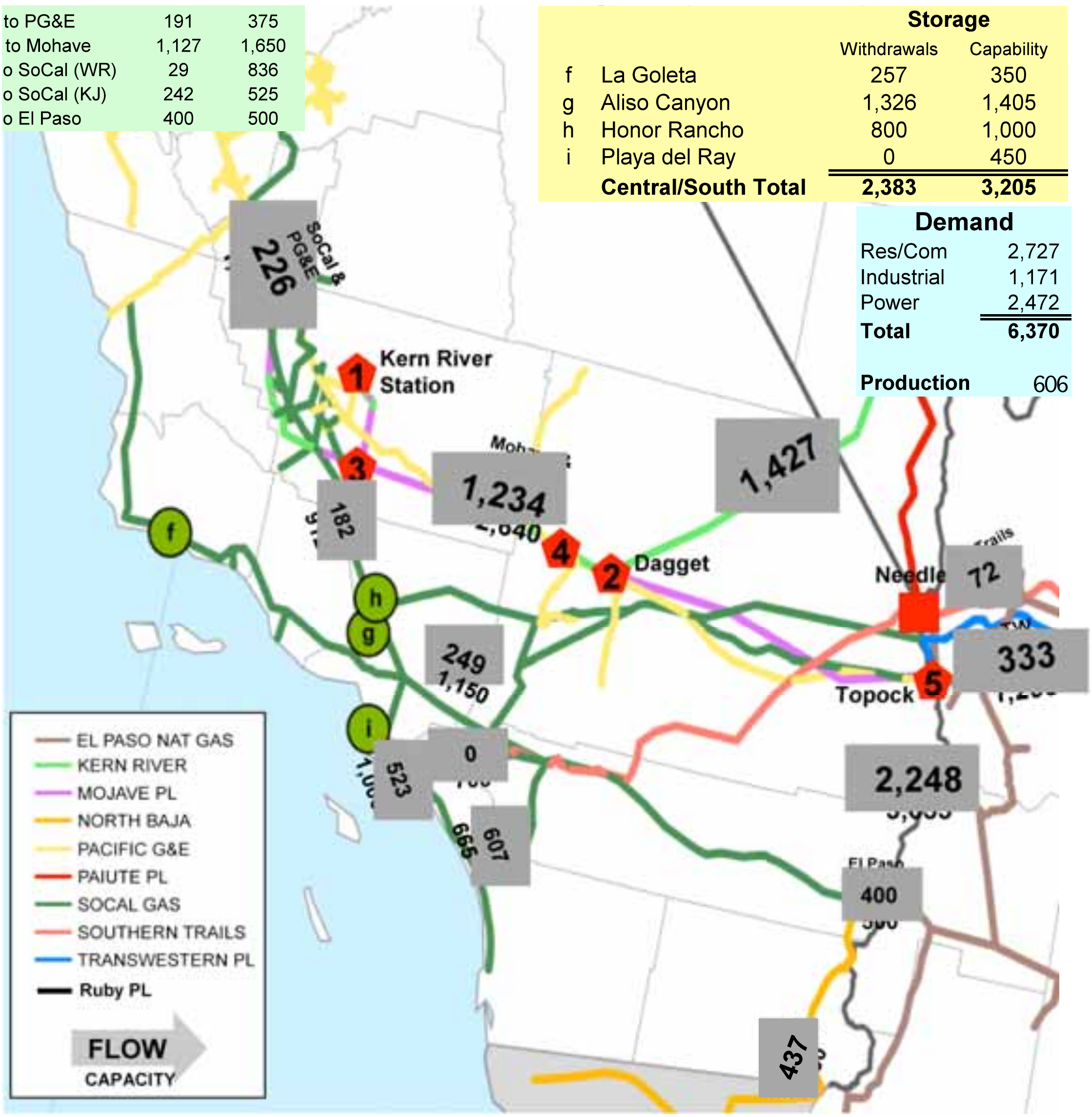


Figure 52: January 2020 Peak day Flows in Southern/Central California (MMCFd), Case 5

Source: ICF International

Average January demand in Southern and Central California in Case 5 are up by only about 80 MMCF compared to Case 2 (Figure 53). Almost all of the incremental demand is met by increased imports on the El Paso system.

Compared to the peak day demand in Case 5, average January demand is about 1.4 BCF lower. Of the additional demand on a peak day, over 900 MMCF is in the residential and commercial sectors. The remaining 450 MMCF is in the power sector. All of the additional supply needed to meet peak day demand is supplied by additional storage withdrawals within the area.

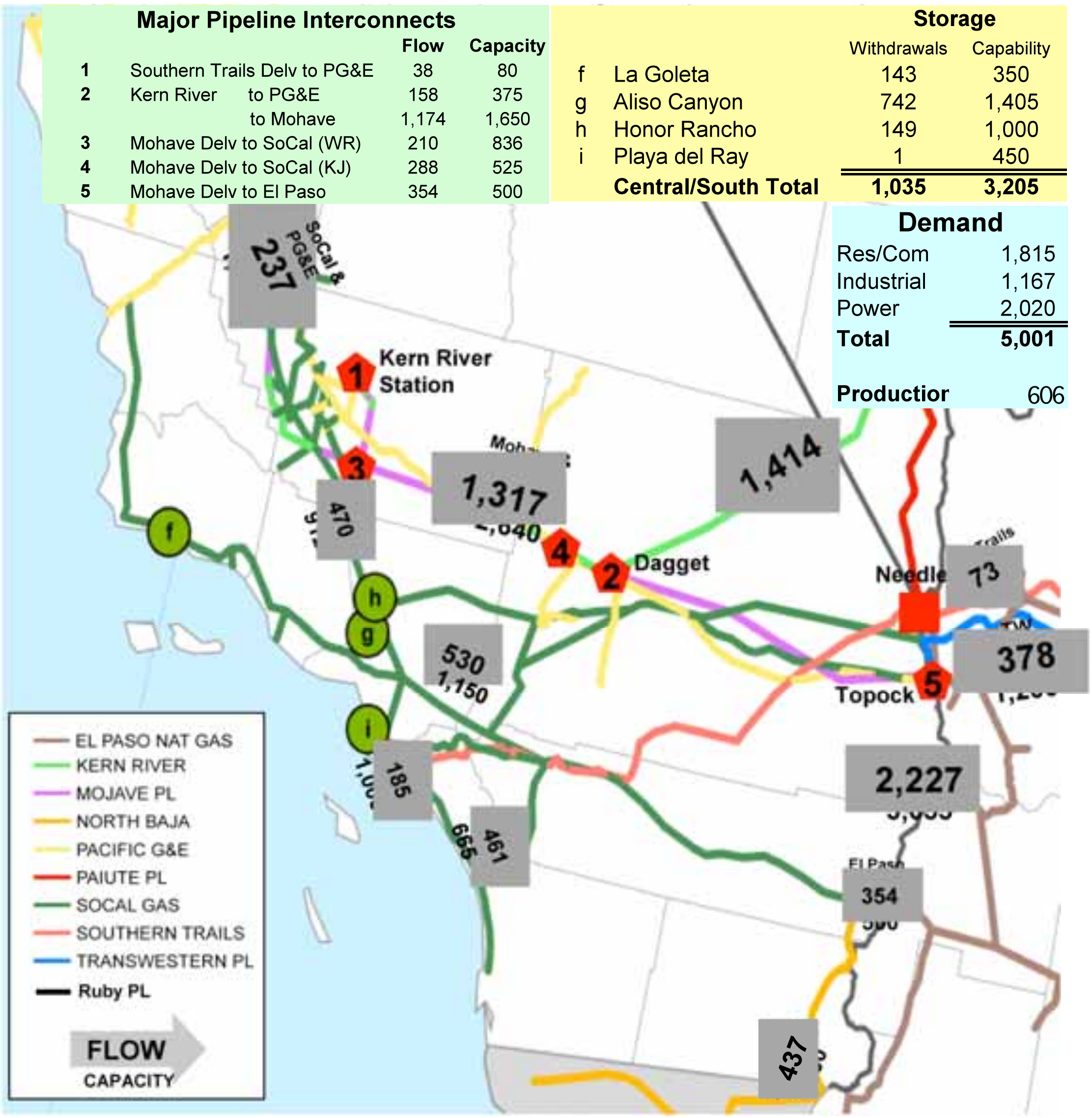


Figure 53: January 2020 Average Flows in Southern/Central California (MMCFd), Case 5

Source: ICF International

Peak day demand in Northern California in Case 5 is up by about 230 MMCF over Case 2 (Figure 54). About 190 MMCF of the increase is met by additional storage withdrawals and about 40 MMCF comes from additional imports at Malin. Similarly to the other two reduced renewable generation cases, four of the eight storage fields in Northern California are withdrawing at their full capability on the peak day. However, even if the withdrawal capability at these fields is being overestimated, there is still remaining unused pipeline import capacity and storage withdrawal capability at other fields to help meet peak day demand.

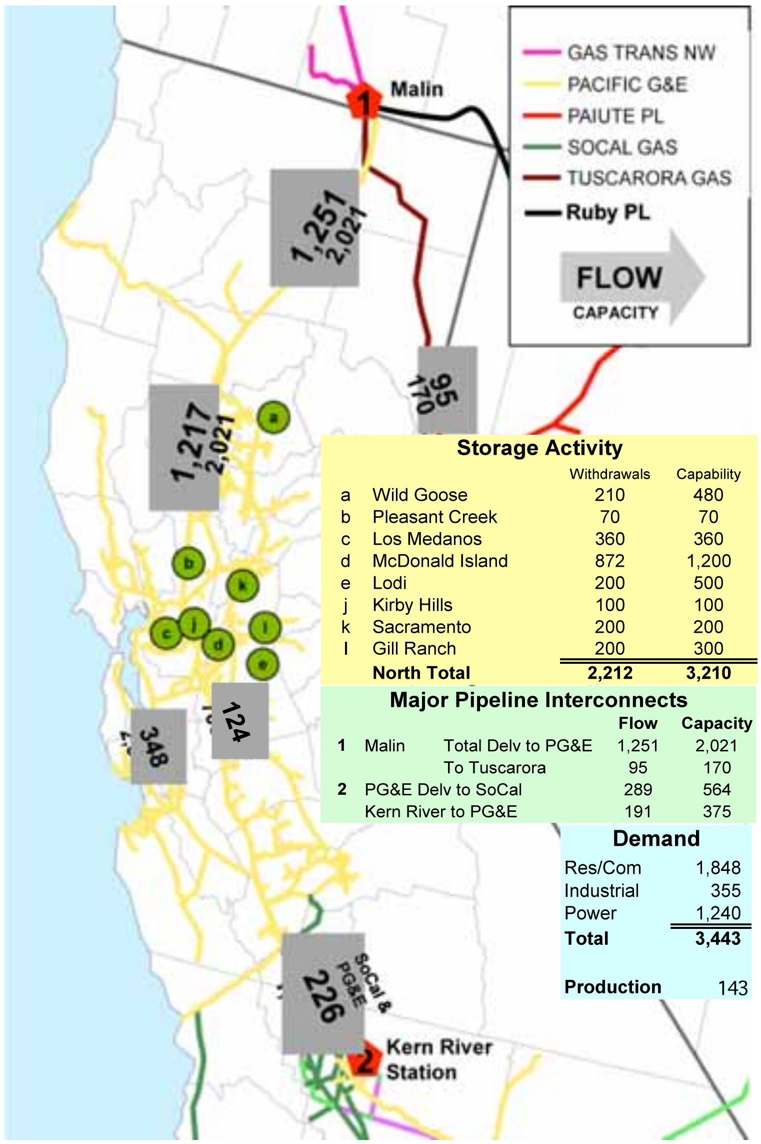


Figure 54: January 2020 Peak Day Flows in Northern California (MMCFd), Case 5

Source: ICF International

In Northern California, average January demand is up only slightly compared to Case 2; demand in Case 5 is only about 50 MMCF higher than in Case 2 (Figure 55). The increase in demand is met by increased in both pipeline imports at Malin and regional storage withdrawals.

Compared to the peak day in Case 5, the average January demand in northern California is about 940 MMCF less. Compared to the average day, gas demand on the peak day is 650 MMCF higher in the residential and commercials sectors, and 280 MMCF higher in the power sector, with a slight increase in industrial demand. All of the additional peak day demand is met with addition storage withdrawal.

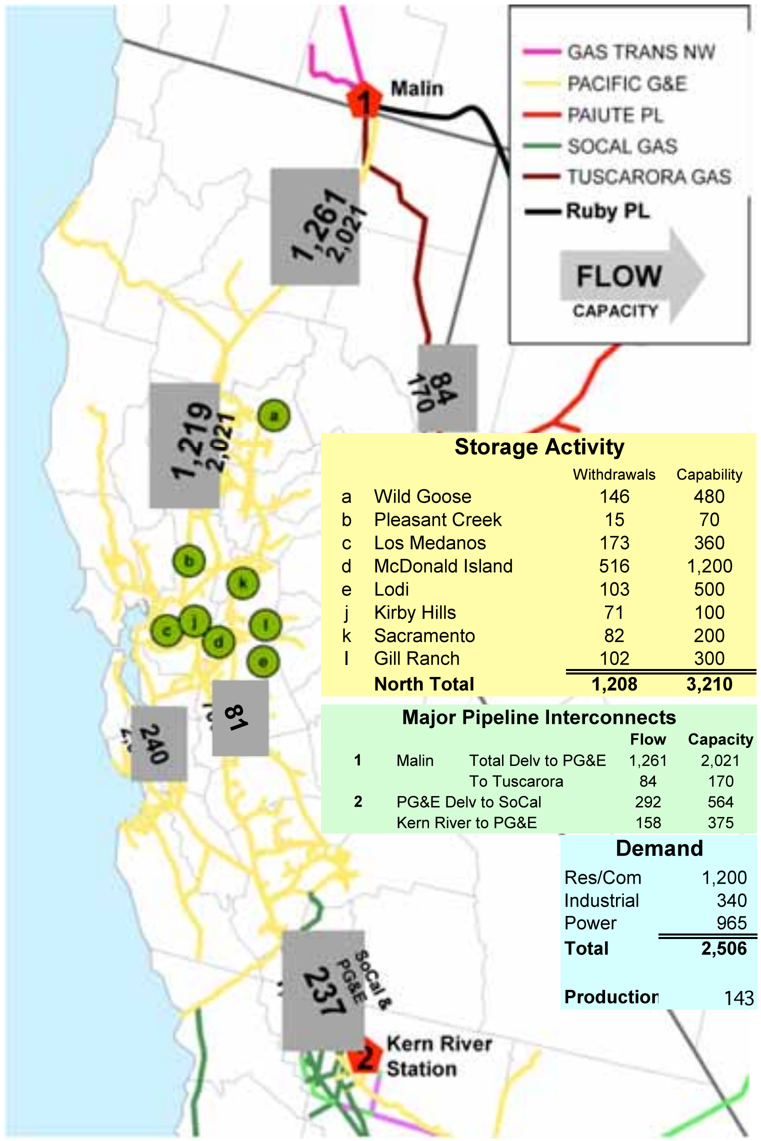


Figure 55: January 2020 Average Flows in Northern California (MMCFd), Case 5
Source: ICF International

6.0 Summary and Conclusions

6.1. Key Assumptions Driving Case Results

As with any modeling analysis, the results of this study are dependent on the underlying assumptions. This section of the report highlights what we have identified as the key assumptions that could cause the outlook for California's natural gas market to deviate from this study's projections.

1. ***Electric Load Growth.*** This analysis used the California Energy Commission's 2007 projection of 1.1 percent per year growth in California's electric load. Many factors, such as the rate of economic growth and the impacts of energy efficiency and DSM programs, can affect the rate of growth in electricity demand. If the rate of electric load growth is greater than assumed, then incremental growth in gas-fired generation and power generation gas demand will most likely be more than projected. Likewise, if electric load growth is lower, then incremental growth in gas-fired generation and power generation gas demand will most likely be less than projected.

2. ***Wind and Solar Variability.*** Historical data on actual wind and solar generation are very limited. While data on historical wind speed and solar radiation are more extensive, they have other limitations, such as the limited number of weather stations located near prime wind and solar locations. Since the estimates for wind and solar variability used in this study are based on a limited amount of data, the potential variability in generation (and the consequential variations in gas demand for power generation) may be more or less than represented in this study.

3. ***Electric Transmission Constraints***. A detailed analysis of California's electric transmission network was outside of the scope of this study. Consequently, the authors assumed that reductions in RPS generation within an area (Northern, Central, or Southern California) will be met with increased gas-fired generation in the same area. Limitations on the ability to transmit electricity within each area could result in a different dispatch pattern for gas-fired power plants, and therefore different loads on the natural gas infrastructure. However, it the electric grid is more robust than represented, power generation gas consumption in areas with pipeline constraints (such as San Diego) may be lower than projected.

4. ***Representation of the Natural Gas Infrastructure***. The analysis is based on a county-level assessment of mainline capacities, storage field locations, and gas demand. There could be potential constraints within counties and in local distribution system that are not apparent in this analysis.

5. ***Hourly Versus Daily Variations in Generation***. This analysis focuses on seasonal and daily variations in renewable generation; the impact of hourly variations has not been assessed. Hourly variations in wind and solar generation could create additional variability in demand for gas-fired generation. However, since pipeline and distribution companies have flexibility in their infrastructure (through line pack and storage) to

respond to hourly variability in gas use, we feel that hour variations in renewable generation would have a minimal impact on gas infrastructure.

6. ***Optimization of Storage Withdrawals***. The RIAMS model, which was used to project intra-state pipeline flows and storage activity, optimizes the use of storage within the month of January to meet peak day demands. That is, the model knows the exact level of gas demand for each day, and will forgo withdrawal on lower demand days to make more gas available on higher demand days. It is possible that on peak gas demand days, actual pipeline flows would be higher and storage withdrawals would be lower than RIAMS projects. However, the results still suggest that there is ample inter- and intra-state pipeline capacity available on peak days.

6.2. Conclusions

6.2.1. A 33 Percent RPS Results in an Incremental Reduction in California's Gas Demand

Using the California Energy Commission's 2007 electric load projection, a 33 percent RPS would result in greater incremental growth in renewable generation than there is growth in electric load. As a result, gas-fired generation is displaced, and gas consumption for power generation decreases over time. With expected levels of renewable generation and normal weather and hydroelectric conditions, California's power sector gas consumption is projected to decline by 0.8 BCFd by 2020. Since projected gas demand in the residential, commercial, and industrial sectors is flat to down, California's total gas demand is projected to decline by 0.9 BCFd by 2020. Even with adverse weather and hydroelectric conditions, which increases average annual gas demand by 0.7 BCFd, gas consumption in 2020 is still projected to be lower than in 2008.

6.2.2. California's Natural Gas Infrastructure is Adequate to Handle Increases in Peak Day Gas Demand Caused by Reduced Renewable Generation

All of the cases with reduced renewable generation cause an incremental increase in January 2020 peak day gas demand of about 0.5 BCFd, but these increases were not enough to cause significant problems for the state's gas pipeline or gas storage infrastructure. All the reduced generation cases show similar results. The High Wind scenario (Case 4) has the greatest generation reductions, but still shows no signs of demand curtailments, pipeline congestion, or storage constraints on the January peak gas demand day. In all cases there was ample pipeline capacity entering the state meet the increase load on a peak demand day. While high, gas storage withdrawals within the estimated operational limits at all fields, and working gas in storage was not pushed to unreliably low levels.

Gas infrastructure within the state is generally adequate to meet the increased January peak day gas demands in all the reduced generation cases, with one possible exception. The San Diego area distribution lines appeared to be congested in both winter and summer peak gas demand periods. Additional pipeline and / or storage infrastructure may be required in this area to ensure system reliability.

6.2.3. California's Natural Gas Supply Options and Infrastructure Improve Over Time

U.S. gas supplies are expected to increase by over 7 BCFd by 2020, mainly due to increases in domestic production. Growth in Rockies gas production has a direct benefit to California, providing more gas supplies via the Kern River Pipeline and the new Ruby Pipeline planned for 2011. Increases in production in other areas can also have a positive impact on California's gas supply outlook by making more gas available throughout the United States.

Several planned projects will increase the supply of natural gas available to California. Ruby Pipeline will provide an addition 1.3 BCFd of pipeline capacity from the Rockies to Malin. Additional compression and looping on Kern River Pipeline will allow for additional flows on that system. While the Costa Azul LNG terminal may not receive enough gas to become a significant supply source for Southern California, those imports will displace the need for some U.S. gas exports to Mexico, and therefore make more gas available to the California market.

New storage capacity in California provides additional flexibility for meeting peak demand. Two new storage fields and one field expansion are planned within the next several years, adding over 33 BCF of storage capacity and 550 MMCFd of maximum withdrawal capability.

6.2.4. Technology Mix and Geographic Diversity in Renewables Minimizes the Potential Impact of Reduced Renewable Generation

While wind and solar generation varies due to changes in weather, other renewable technologies, such as biomass, biogas, and geothermal, do not. All the scenarios assumed between 38 percent and 41 percent of future RPS generation come from these non-intermittent technologies, which dampens the potential for variability in total renewable generation.

While both wind and solar technologies have distinct seasonal patterns to their output, to some extent these normal seasonal patterns complement each other. In the summer months, when electric load is highest, wind generation is at its lowest but solar generation is at its highest. Having a mix of both wind and solar generation helps dampen out the seasonal variations of each technology.

Seasonal variations in wind and solar technology also compliment the seasonal patterns in electricity demand and gas demand. Both wind and solar generation are relatively low in the winter months, when electricity demand is also relatively low. In the summer, when electricity demand peaks, residential and commercial gas demands are at their lowest levels. This means that in the summer more gas supplies and pipeline capacity are available to meet increased power sector gas demand should renewable generation fall short of expected values.

Geographic diversity also enhances the reliability of intermittent renewable technologies. For example, wind generation can be highly variable at any particular site in California. However, based on historic weather data, it appears unlikely that there would be unfavorable wind conditions simultaneously throughout the state. Having wind farms at many different locations reduces the variability of California's total supply of wind generation.

Glossary

BCF	Billion cubic feet
BCFd	Billion cubic feet per day
Energy Commission	California Energy Commission
CPUC	California Public Utility Commission
DGLM	Daily Gas Load Model
DSM	Demand side management
FERC	Federal Energy Regulatory Commission
GMM	Gas Market Model
GW	Gigawatt
GWh	Gigawatt-hours
LNG	Liquefied natural gas
MMCF	Million cubic feet
MMcCFd	Million cubic feet per day
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
PG&E	Pacific Gas and Electric
PV	Photovoltaic
RIAMS	Regional Infrastructure Assessment Modeling System
RPS	Renewables Portfolio Standard
TCF	Trillion cubic feet
TWh	Terawatt-hours